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May 29, 2014

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MAY 30 2014
PUBLIC SERVICE COMMISSION

Federal Express

Mr. Jeff Derouen
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: Big Rivers Electric Corporation
Administrative Case No. 387

Dear Mr. Derouen:

Enclosed are an original and ten (10) copies of (i) Big Rivers Electric Corporation's responses to the information requested in your letter to me dated May 19, 2014, and (ii) a petition for confidential treatment. Please feel free to contact me with any questions.

Sincerely,

TK

Tyson Kamuf

TAK/lm
Enclosures

cc. DeAnna Speed
Roger Hickman

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ORIGINAL

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matters of:

A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM	)	Administrative Case No. 387
REQUEST OF BIG RIVERS ELECTRIC CORPORATION FOR AN EXTENSION TO FILE THE ANNUAL INFORMATION REQUIRED BY AN ORDER IN ADMINISTRATIVE CASE NO. 387	)	Case No. 2014-00036

Response to Commission Staff's Supplemental Information Request from its Letter dated May 19, 2014

FILED: May 30, 2014

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

SUPPLEMENTAL INFORMATION PROVIDED WITH
BIG RIVERS' ANNUAL FINANCIAL AND STATISTICAL REPORT
PURSUANT TO ADMINISTRATIVE CASE NO. 387 –
A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION
CAPACITY AND TRANSMISSION SYSTEM

**Response to Commission Staff's
Supplemental Information Request
from its Letter dated May 19, 2014**

June 2, 2014

Supplemental Item 1) ***Refer to Big Rivers' response to Item 7 in its filing of April 25, 2014.***

a. Provide the calculation of the 7.3 percent target reserve margin used for planning purposes. Include all necessary narrative descriptions of the steps in the calculation and the source of all data used in the calculation.

b. When applying the 7.3 percent target reserve margin, does it refer to the reserve margin required at Big Rivers peak or coincident to MISO's peak?

Response)

a. The 7.3 percent target reserve margin used for planning purposes is as specified by MISO for the upcoming planning year effective June 1, 2014. Details on this calculation are available in the "MISO Planning Year 2014 LOLE Study Report" prepared by the Loss of Load Expectation Working Group, (attached, starting on page 40) and available at: https://www.misoenergy.org/Library/Repository/Study/LOLE/2014%20LOLE%20Study%20Report.pdf.

b. The 7.3 percent target reserve margin used for planning purposes refers to the margin of unforced capacity available above Big Rivers' peak, [redacted]

BIG RIVERS ELECTRIC CORPORATION

SUPPLEMENTAL INFORMATION PROVIDED WITH BIG RIVERS' ANNUAL FINANCIAL AND STATISTICAL REPORT PURSUANT TO ADMINISTRATIVE CASE NO. 387 – A REVIEW OF THE ADEQUACY OF KENTUCKY'S GENERATION CAPACITY AND TRANSMISSION SYSTEM

Response to Commission Staff's Supplemental Information Request from its Letter dated May 19, 2014

June 2, 2014

Respondent) Marlene S. Parsley

Planning Year 2014 LOLE Study Report

Loss of Load Expectation Working Group (LOLEWG)

Contents

Revision History

Reason for Revision	Revised by:	Date:
Final Posted	MISO Staff	11/1/2013
Updated Tables 1.1-1, 6.1-1, 6.1-2, and 6.1-3. Changes reflect the physical location of pseudo-tied capacity	MISO Staff	2/7/2014

1 Executive Summary

Midcontinent Independent System Operator (MISO) conducts an annual Loss of Load Expectation (LOLE) study to determine a Planning Reserve Margin Unforced Capacity (PRM_{UCAP}), zonal per-unit Local Reliability Requirements (LRR), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). The results of the study and its deliverables supply inputs to the MISO Planning Resource Auction (PRA). For 2013, the LOLE study underwent significant alterations as the integration of the MISO South region into the analysis necessitated study process changes.

Key findings and results from the 2013 LOLE study include:

- A PRM_{UCAP} of 7.3 percent being applied to the Load Serving Entity (LSE) coincident peaks has been established for the planning year starting June 2014 and ending May 2015
- The use of the GE Multi-Area Reliability Simulation (MARS) software for Loss of Load analysis provided results applicable across the MISO market footprint, while any impacts due to transmission limitations will be addressed in the PRA
- This report provides the PRA with the overall 7.3 percent PRM_{UCAP} requirement, the per-unit LRR values and the initial zonal CIL and CEL for each Local Resource Zone (LRZ). The CILs and CELs may be adjusted within the PRA to assure that the resources cleared in the auction can be reliably delivered simultaneously.
- In accordance with the MISO Tariff, the reliability objective of an LOLE study is to determine a minimum planning reserve margin that would result in the MISO system experiencing a less than one day loss of load event every 10 years.[1] The MISO analysis shows that the system would achieve this reliability level when the amount of installed capacity available is 1.148 times that of the MISO system coincident peak.
- Zonal-based deliverables are set forth in the LOLE charter (Table 1.1-1)

RA and LOLE Metrics	LRZ-1	LRZ-2	LRZ-3	LRZ-4	LRZ-5	LRZ-6	LRZ-7	LRZ-8	LRZ-9
MISO PRM_{UCAP}	7.3%	7.3%	7.3%	7.3%	7.3%	7.3%	7.3%	7.3%	7.3%
LRR UCAP per unit of LRZ Peak Demand	1.107	1.153	1.147	1.182	1.198	1.118	1.152	1.293	1.124
Capacity Import Limit (CIL) (MW)	4,347	3,083	1,591	3,025	5,273	4,834	3,884	1,602	3,585
Capacity Export Limit (CEL) (MW)	286	1,924	1,875	1,961	1,350	2,246	4,517	3,080	3,816

Table 1.1-1: 2014 Planning Resource Auction deliverables

[1] A one-day loss of load in 10 years (0.1 day/year) is not necessarily equal to 24 hours loss of load in 10 years (2.4 hours/year).

Study Enhancements

For the 2014-2015 planning year, significant changes were made to LOLE study due to MISO South's integration into MISO. The addition of MISO South added a large amount of generation and load to the MISO footprint as well as two new LRZ (Figure 1.1-1). Modeling enhancements became necessary in order to mature and stabilize the planning reserve margin and reliability requirements.

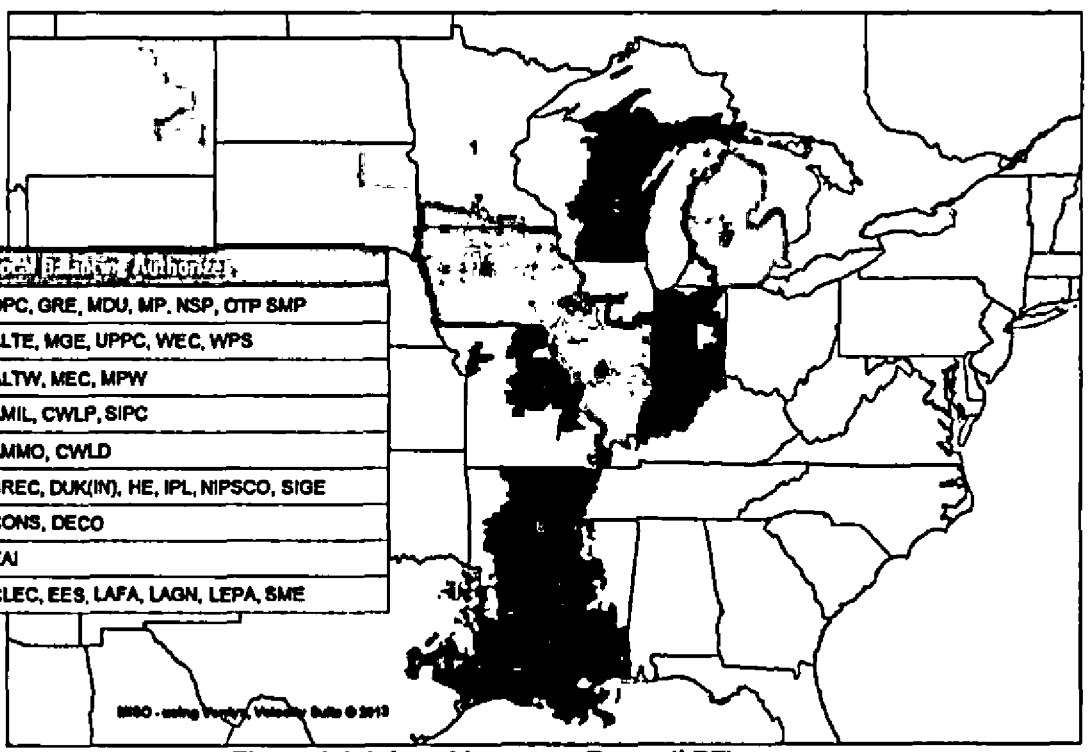
MISO enhanced the LOLE analysis as follows:

- The adjustment of capacity for a particular study area to meet 0.1 days per year LOLE was aligned with the MISO Tariff
- The Load Forecast Uncertainty (LFU) calculation was refined and improved and the LFU modeling methodology was improved for consistency between the MISO and LRZ LOLE analyses
- The amount of external support MISO can receive in times of need was enhanced so that a more accurate reflection of this support is modeled
- The transfer analysis methodology used to determine the CIL and CEL values went through many improvements

All of these enhancements are discussed in further detail throughout this report.

Acknowledgements

The stakeholder review process played an integral role in this study and the collaboration of the Loss of Load Expectation Working Group (LOLEWG) was much appreciated by the MISO staff involved in this study. Stakeholder review was especially valuable this year as the MISO Resource Adequacy zonal construct was implemented for the second annual PRA as well as the integration of MISO South.



LRZ	Local Balancing Authority
1	DPC, GRE, MDU, MP, NSP, OTP SMP
2	ALTE, MGE, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA, SME

Figure 1.1-1: Local Resource Zones (LRZ)

2 LOLE Study Process Overview

In compliance with Module E-1 of the MISO Tariff, MISO performed its annual Loss of Load Expectation (LOLE) study to determine the Planning Reserve Margin (PRM) on an unforced capacity (UCAP) basis for the MISO system and the per-unit Local Reliability Requirements (LRR) of Local Resource Zone (LRZ) Peak Demand for the planning year 2014-2015.

In addition to the LOLE analysis, a transfer analysis was performed to determine Capacity Import Limits (CIL) and Capacity Export Limits (CEL). The CIL is used in conjunction with the LOLE analysis results in the Planning Resource Auction (PRA). The 2014-2015 per-unit LRR_{UCAP} values determined by the LOLE analysis will be multiplied by the updated LRZ Peak Demand[2] forecasts submitted for the 2014-2015 Planning Resource Auction to determine each LRZ's LRR. Once the LRR is determined, the CIL values are subtracted from the LRR to determine each LRZ's Local Clearing Requirement (LCR) consistent with Section 68A.6[3] of Module E-1. Table 2.0-1 shows an example calculation pursuant to Section 68A.6 of the current effective Module E-1.[4] The actual effective PRM Requirement (PRMR) will be determined when the updated LRZ Peak Demand forecasts are submitted in the 2014-2015 PRA and the simultaneous feasibility test is complete, which ensures CIL and CEL values are not violated.

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Capacity Import Limit (CIL)	3,469	[G]
Capacity Export Limit (CEL)	2,317	[H]
Proposed PRA (UCAP) EXAMPLE	**Example LRZ**	**Formula Key**
Forecasted LRZ Peak Demand	14,270	[I]
Forecasted LRZ Coincident Peak Demand	13,939	[J]
Local Reliability Requirement (LRR) UCAP	16,382	[K]=[F]x[I]
Local Clearing Requirement (LCR)	12,913	[L]=[K]-[G]
Zone's System Wide PRMR	14,957	[M]=[1.073]X[J]
Effective PRMR	14,957	[N]= Higher of [L] or [M]
Effective PRM	7.3%	[O]=[N]/[J]-1

Table 2.0-1: Example LRZ calculation

2.1 Future Study Improvement Considerations

The calculation of the 2014 MISO PRM values captures firm external capacity purchases and sales in the accounting of the installed and unforced capacity values. These firm transactions are treated differently

2 https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=158707
3 https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx#
4 Effective Date: November 1, 2013

for the LRZ LOLE analysis. External sales to PJM Interconnection were derated from the available capacity in that particular LRZ. However, firm purchases were not modeled as required by the MISO Tariff. Section 68A.5[5] of Module E-1 of the MISO Tariff states the LRR should be determined "without consideration of the LRZ's CIL." MISO realizes there is an inconsistency here and that there is potential for possible improvements in future studies.

The LOLE analysis utilizes a five-year Equivalent Forced Outage Rate Demand (EFORd) value to determine the PRM and LRR values. This differs from what resources use as their forced outage rate in the PRA. In the PRA, resources use a three-year XEFORd value, which excludes impacts for outages that were caused by events Outside Management Control (OMC). The reasons for these differences can be discussed for future studies.

Industry standard practice in the adjustment of capacity to meet 0.1 days per year LOLE is to add a perfect negative or positive unit within the model. However, the MISO tariff explicitly describes a different methodology in determination of LRZ LRR. Understanding the tariff methodology and possible future changes to the adjustment methodology should be discussed for future LOLE studies to address any impact of this inconsistency.

Currently, the LCR = LRR – CIL, which is a linear relationship. Further analysis is needed to refine the relationship of CIL to LCR. A future goal is to provide a range of LCRs depending on a range of support available to each zone. Analysis to derive a more representative LCR as a function of CIL should be investigated.

MISO LOLE analysis utilizes Operating Reserves in the calculation of the PRM values rather than holding them aside. In other words, the PRMR does not procure sufficient Planning Resources to hold Operating Reserves during a LOL event. This assumption should be revisited for consideration in future studies; including how other RTOs handle these requirements.

The 2014 study modeled all Network Resources and Energy Resources in the determination of the PRM. This approach should be validated prior to future studies.

Demand Response and Wind Generation Resource modeling in the LOLE analysis should be revisited based on the Independent Market Monitor's (IMM) 2012 State of the Market Recommendations. Modeling Behind-the-Meter-Generation (BTMG) with an Installed Capacity (ICAP) and its associated forced outage rate could be implemented to align with Capacity Resource qualification. Additionally, treatment of wind resources in the LOLE analysis, and the capacity credit for qualified wind resources should be reviewed.

As the CIL and CEL study process matures, MISO expects to identify additional improvements. Possible improvements for the 2014 study include:

- MISO to create model summaries at the zonal or area level to facilitate model review
- Setting MISO wind dispatch to capacity credit levels
- July 15 effective date for the near-term model
- Administration of all changes to models through Model On-Demand (MOD)
- Adding interregional coordination requirements at the start of the study

[5] https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx#

3 Transfer Analysis

3.1 Calculation Methodology and Process Description

Transfer analysis is used to establish Capacity Import Limits (CILs) and Capacity Export Limits (CELs) for Local Resource Zones (LRZs) in the Planning Reserve Margin (PRM) study for the 2014-2015 planning year. The objective of this study is to determine how import capability for each zone can potentially delay the build of additional capacity. There were significant enhancements to this year's analysis. This includes consideration of all facilities under MISO functional control, regardless of the voltage level, as potentially limiting and utilizing MISO generation local to a zone for import limit analyses. For this planning year an effort was made to more thoroughly document study assumptions, procedures, progress and results through Business Practice Manual (BPM) language and Loss of Load Expectation Working Group (LOLEWG) meeting materials.

Other improvements to the transfer analysis include the following enhancements, which help more accurately represent the capacity import and export limits of each LRZ.

- Excluding additional units from transfer analysis based on machine parameters
- Redispatch options considered for mitigation
- Setting MISO import level to net firm level

An additional improvement was the determination of capacity import and export limits for five-year and 10-year timeframes. These results are useful for planning and indicate what changes can be expected based on future modifications to the system.

3.1.1 Tiered generation pools

To determine an LRZ's import or export limits, a generation-to-generation transfer is modeled from a source subsystem to a sink subsystem. For import limits, the limit is determined for the sink subsystem. Import limits are found by increasing MISO generation resources in close electrical proximity to the LRZ under study while decreasing generation inside the LRZ under study (Figure 3.1-1).

- Tier 1 – Generation in the MISO areas with ties to the LRZ under study
- Tier 2 – Tier 1 plus generation in MISO areas with ties to Tier 1

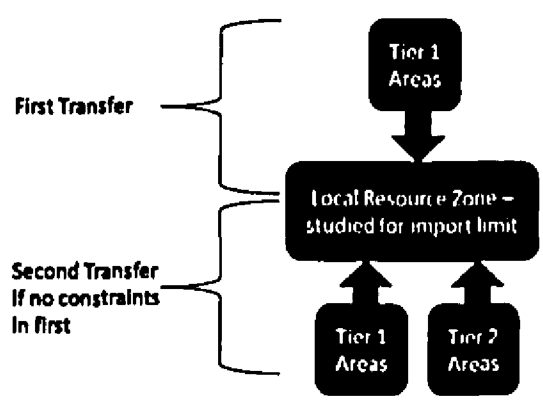


Figure 3.1-1: Tiered Import Illustration

Import limit studies are analyzed first using Tier 1 generation only. If a constraint is identified, redispatch is tested. If redispatch mitigates the constraint completely and an additional constraint is not identified, the limit is the adjusted available capacity in Tier 1 plus any base import or minus any base export. Available capacity must be adjusted to account for changes due to redispatch. If a constraint is not identified using Tier 1 generation only, Tier 2 generation is then considered using the same redispatch process. If constraints are identified using Tier 1 generation, Tier 2 generation is not needed to determine the zone's import limit.

Stakeholders voiced concern over the tiered approach; however the following reasons support the application of this methodology:

- The tiered approach reduces the likelihood of limits due to remote constraints, which occurred in previous studies
- The prior methodology utilized all MISO and seam-area generation for each import scenario
- The tiered approach pools Generation Resources for import studies providing a prudent transmission limit using only local MISO generation
- More accurate representation of the conservative transfer limits in effect during emergency situations

The tiered approach was not applied to export studies. Generation within the zone being studied for an export limit is being ramped up. Constraints are expected to be near the zone because the generation being ramped up is in a more concentrated area than import studies.

3.1.2 Redispatch

Redispatch was completed similarly to redispatch for baseline reliability projects, which is referenced in Section J.5.1.1 of the Transmission Planning Business Practice Manual (BPM)[6]. The common assumptions are as follows:

- Only shift factors greater than 3 percent are considered
- No more than 10 conventional fuel units or wind plants will be used
- Redispatch limited to 2,000 MW total
- Nuclear units are excluded

Figure 3.1-2 summarizes the redispatch assumptions for import scenarios.

[6] BPM 020 – Transmission Planning: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19215

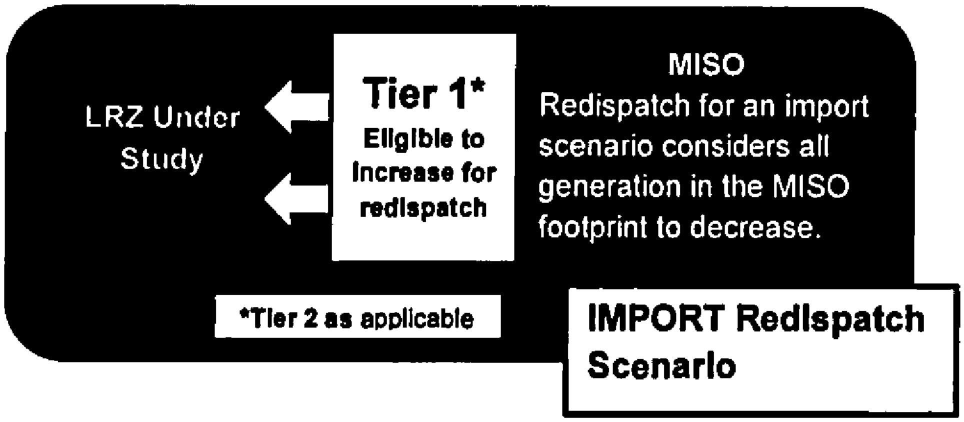


Figure 3.1-2: Import Redispatch Scenario

For import redispatch scenarios, all MISO generators studied outside of the zone will be considered as ramped down. Only units in the tier used to identify the constraint are considered as ramped up. Initially, only MISO generation in the constraint-identified tier was considered to ramp up and down but, based on stakeholder feedback and MISO review, this assumption was too restrictive for constraints near zonal borders. This new process ensures that resources are in the vicinity of the study area. It is unreasonable to assume ramping down a unit with a significant impact on the constraint by 2 MW, for example, can be offset by ramping up a far-away unit by 2 MW. Generation within the importing zone is decreased, therefore it is not considered for redispatch.

For export redispatch scenarios, only generation within the zone being studied is considered to be ramped up or down (Figure 3.1-3).

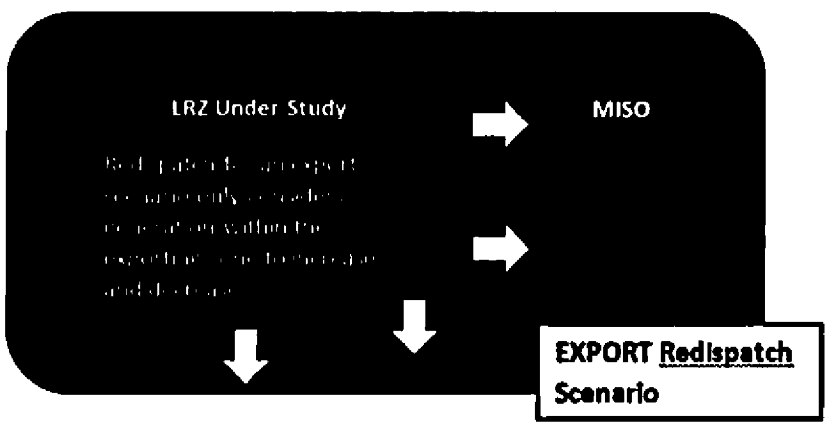


Figure 3.1-3: Export Redispatch Scenario

3.2 Power Flow Models and Assumptions

3.2.1 Tools used

Siemens PTI Power System Simulator for Engineering (PSS E), Version 32.2.0 and Power System Simulator for Managing and Utilizing System Transmission (PSS MUST), Version 11.0.1 were utilized for the transfer analysis.

3.2.2 Inputs required

The study required power flow models and PSS MUST input files. PSS MUST contingency files from Coordinated Seasonal Assessment (CSA) and MTEP[7] reliability assessment studies were used (Table 3.2-1). Single-element contingencies in MISO and seam areas were evaluated in addition to submitted files.

Model	Contingency files used
2014-15 Planning Year	2013 Summer CSA
5-year-out peak	MTEP13 study
10-year-out peak	MTEP13 study

Table 3.2-1: Contingency files per model

PSS MUST subsystem files include LRZ, Tier 1 and Tier 2 definitions. Refer to Appendix C for maps containing Tiers used for this study. The PSS MUST monitored file includes all facilities under MISO functional control.

Table 3.2-2 summarizes when the inputs required are available. These dates will be reasonably consistent for future studies.

Input(s) Available for LOLE PRM Analyses	Date
Appendix A Project Info[8]	September 15, 2012
MTEP 5- and 10-Year Models[8]	February 15, 2013
Access Planning 1-Year Model[9]	February 2013
Summer CSA Contingency files	May 31, 2013
MTEP NERC TPL contingencies	June 2013

Table 3.2-2: Input availability dates

3.2.3 Power Flow Modeling

Three summer peak models were required for the analysis: 2014, 2018 and 2023. All models were built using MISO's Model on Demand (MOD) model data repository, each with an effective date and base assumptions (Table 3.2-3).

[7] Refer to sections 4.3.4 and 4.3.6 of the Transmission Planning BPM for more information regarding MTEP PSS MUST input files. https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19215
[8] Refer to MTEP Information Exchange Document: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=115852
[9] Information regarding model progress presented at sub-regional planning meetings

Planning Year	Effective Date	Projects Applied	External Modeling	Load and Generation Profile
2014-15	6/1/2014	Approved MTEP12 A	ERAG MMWG	Summer Peak
2018	7/15/2018	Approved MTEP12 A	ERAG MMWG	Summer Peak
2023	7/15/2023	Approved MTEP12 A	ERAG MMWG	Summer Peak

Table 3.2-3: Model assumptions

Several types of units had to be modified so their participation in transfers would be prudent.

- Nuclear units were excluded from all transfers; therefore dispatch changes were not made to these units
- Must-run, self-scheduled, system support resources and hydro generating units identified using the MTEP Regional Merit Dispatch file were also excluded from transfers
- MISO South Voltage and Local Reliability units (historically Reliability Must Run units) had their dispatches fixed per posted operating guides

System conditions such as load, dispatch, topology and interchange have an impact on transfer capability. In addition to the dispatch exclusions, generators with negative Pmin values were modified so that the Pmin was either set to zero or its MOD profile dispatch if that value was negative. This ensured these units were not used to transfer power.

Relying on seam areas beyond firm commitments was a drawback of the prior methodology. Net firm reservations were modeled this year and external units were not included in any transfers beyond the firm level. Stakeholders voiced concern about not including externals beyond the firm level. MISO believes the net firm modeling is appropriate because there is no certainty for any non-firm transactions if MISO is in a loss-of-load event. Also, if MISO is in a loss-of-load event, it is possible adjacent regions could be as well. MISO import levels in the base case will be set to the level of firm transactions.

Stakeholder review of models and input files was requested through LOLEWG meetings and by notices sent to these MISO groups: Planning Advisory Committee, Planning Subcommittee and the Regional Expansion Criteria and Benefits (RECB) Task Force. Files were made available on the MTEP ftp site. Feedback regarding transmission facilities modeling and ratings was sought.

3.2.4 General Assumptions

PSS MUST uses the power flow model and associated input files to determine the import and export limits of each LRZ by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under certain system conditions and is used as an indicator of transmission strength. The incremental amount of power that can be transferred will be determined through First Contingency Incremental Transfer Capability (FCITC) analysis. FCITC analysis provides information to calculate the Total Transfer Capability (TTC), which indicates the total amount of power able to be transferred before a constraint is identified. TTC is the base power transfer plus the incremental transfer capability (Equation 3.2-1).

$$\textit{Total Transfer Capability (TTC)} = \textit{FCITC} + \textit{Base Power Transfer}$$

Equation 3.2-1: Total Transfer Capability

Facilities were flagged as potential constraints for loadings of 100 percent or more of the normal rating for North American Electric Reliability Corporation (NERC) Category A conditions and loadings of 100 percent or more of the emergency rating for NERC Category B contingencies. Available capacity in source subsystems was noted to ensure machine limits were respected in the analyses.

Linear FCITC analysis identifies the limiting constraints using a minimum Distribution Factor (DF) cutoff of 3 percent, meaning the transfer and contingency must increase the loading on the overloaded element by 3 percent or more.

FCITC requires a defined transfer level, which is the amount of power that will be transferred from the source subsystem to the sink subsystem. The transfer level is determined by the available export capability of the source subsystem. This will ensure that machine limits in the source subsystem are not violated.

A pro-rata dispatch is used, which ensures all available generators will reach their max dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit. Table 3.2-4 and Equation 3.3-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem. MISO wind resources are excluded from source dispatch by setting the maximum dispatch level of each unit to its current dispatch level in the power flow model (Maximum Dispatch = Unit Dispatch value).

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	310

Table 3.2-4: Example subsystem

$$Machine\ 1\ Post\ Transfer\ Dispatch = \frac{(Machine\ 1\ Reserve\ MW)}{(Source\ Subsystem\ Reserve\ MW * Transfer\ Level\ MW)}$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = \frac{80}{310 * 100} = 25.8$$

$$Machine\ 1\ Post\ Transfer\ Dispatch = 25.8$$

Equation 3.3-2: Machine 1 dispatch calculation for 100 MW transfer

3.3 Results

The results for each LRZ consist of a list of constraints and their corresponding FCITC values up to the raquested transfer level. The constraint with the smallest FCITC was used to determine the CIL and CEL. Invalid constraints were identified for several reasons, such as outdated ratings, invalid contingencies, solution tolerance settings, or associated operating guides that mitigate the constraint. The CIL and CEL ara the TTC of the corresponding limiting constraint. Section 3.5 of the Resource Adequacy BPM provides additional information regarding how the CIL impacts the Local Clearing Requirement calculation. Constraints and associated limits for each planning year wera prasented and reviewed through the LOLE Working Group. This activity occurred in the meetings that took place in July through October 2013.

Initial results wera presented at the July 17, 2013, LOLEWG meeting. It was later determined that generation profiles wera inappropriately applied to the model. The intent was to align power flow and probabilistic load and generation profiles. The model used for the July 17 results aligned generation profiles but did not align load profiles between what is submitted in Module E Capacity Tracking (MECT) tool and Model on Demand. Load and generation profiles are aligned in the Simultaneous Feasibility Study completed as part of the auction. The model was updated using consistent information from Model on Demand as appropriate for power flow models. This model rework resulted in some time delay in providing updated Capacity Import Limits.

Draft Capacity Import and Export Limits were presented at the September 4, 2013, LOLEWG meeting with the updated model. The details pertaining to the results for each zone ara presented in Appendix C: Transfer Analysis. During the September 4 LOLEWG meeting much discussion ensued regarding the tiered approach that had been presented at the June, July and August LOLEWG meetings with requests for feedback. Feedback received in this discussion supported that generation considered for redispatch scenarios should include all MISO generation. Previously, the generation considered for redispatch focused on generation within the source and sink areas. MISO agreed with this feedback and applied it uniformly for each zone. The zones that wera impacted by this change are zones 2, 3 and 8.

Detailed constraint and redispatch information for all 2014 limits is found in Appendix C: Transfer Analysis of this report. A summary of the 2014 Capacity Import Limits is in Table 3.3-1.

Zone	Tier	14-15 Limit (MW)[10]	Monitored Element	Contingent Element	Figure 3.3-1 Map ID	Initial Limit (MW)[11]	Generation Redispatch Details MWs	Area
1	1	4,347	Lime Creek – 161 kV	Barton – Adams 161 kV	1	4,292	68	9 generators in ALTW, WPS, and ALTE
2	1	3,083	Turkey River – Stoneman 161kV	Genoa – Seneca 161 kV	2	2,859	162	10 generators in ALTW, XEL and DPC
3	1	1,591	Palmyra 345/161 kV transformer	Hills – Sub T – Louisa 345 kV	3	0	366	10 generators in AMMO, GRE, and ALTE
4	1	3,025	Tazewell 345/138 kV transformer 1	Tazewell 345/138 kV transformer 2	4	3,025	Not applicable	
5	1	5,273	Hot Springs EHV – Arklahoma 115 kV	Carpenter – Arklahoma 115 kV	5	4,712	539	9 generators in EAI
6	1	4,834	Wheatland – Petersburg 345 kV	Jefferson – Rockport 765 kV	6	4,834	Not applicable	
7	2	3,884	Zion Station – Zion Energy Center 345 kV	Pleasant Prairie – Zion 345 kV	7	2,587	318	10 generators in NIPS, WEC, and AMIL
8	1	1,602	Vienna – Mt Olive 115 kV	Mt Olive – Eldorado 500 kV	8	578	678	10 generators in CLECO, AMMO, and EES
9	1	3,585	Walnut Grove – Swartz 115 kV	Perryville – Baxter Wilson 500 kV	8	3,585	Not applicable	

Table 3.3-1: Planning Year 2014–2015 Capacity Import Limits

[10] The 14-15 Limit represents the limit after redispatch has been considered.
[11] The Initial Limit represents the limit before considering redispatch.

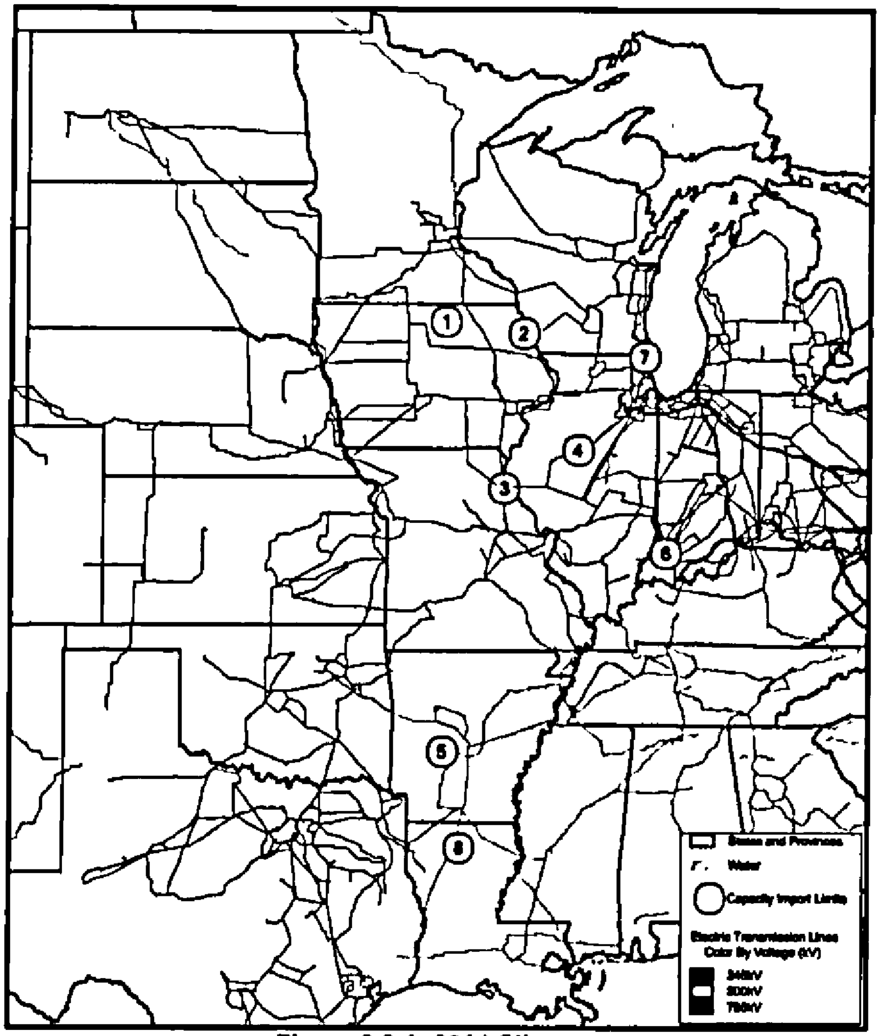


Figure 3.3-1: 2014 CIL map

Tiers were not applied to export scenarios; exports were evaluated from the zone under study to the MISO footprint. Table 3.3-2 summarizes the 2014 Capacity Export Limits.

Zone	14-15 Limit (MW)	Monitored Element	Contingent Element	Figure 3.3-2 Map ID	Initial Limit (MW)	Generation Redispatch Details MWs	Area
1	286	Lakefield - Dickinson 161 kV	Webster 345 kV Station	1	48	515	10 generators in GRE, NSP, and DPC
2	1,924	Zion Station - Zion Energy Center 345 kV	Pleasant Prairie - Zion 345 kV	2	1,371	318	10 generators in NIPS, WEC, and AMIL
3	1,875	Oak Grove - Galesburg 161 kV	Nelson - Electric Junction 345 kV	3	1,875	Not Applicable	
4	1,961	Pontiac - Loretto 345 kV	345-L8014_T_-S[12]	4	1,961	Not Applicable	
5	1,350	Palmyra 345/161 kV Transformer	Hills - Sub T - Louisa 345 kV	5	793	238	10 generators in AMMO and CWLD
6	2,246	Amo - Edwardsport 345 kV	Gibson - Wheatland 345 kV	6	2,246	Not Applicable	
7	4,517	Benton Harbor 345/138 kV Transformer	Benton Harbor - Cook 345 kV	7	4,517	Not Applicable	
8	3,080	Russellville East - Russellville North 161 kV	Arkansas Nuclear one - Ft. Smith 500 kV	8	3018	674	8 generators in EAI
9	3,616	Winnfield 230/115 kV Transformer	Montgomery - Clarence 230 kV	9	2,051	832	10 generators in EES, SME, CLECO

Table 3.3-2: Planning Year 2014–2015 Capacity Export Limits

[12] 345-L8014_T_-S
Close 272260 PONTIAC; B 138 272261 PONTIAC; R 138Z1
Open 270717 DRESDEN; R 345 270853 PONTIAC; R 345 1
Open 270853 PONTIAC; R 345 275210 PONTIAC;2M 138 1
Open 272261 PONTIAC; R 138 275210 PONTIAC;2M 138 1
Open 275210 PONTIAC; 2M 138 275310 PONTIAC; 2C34.5 1

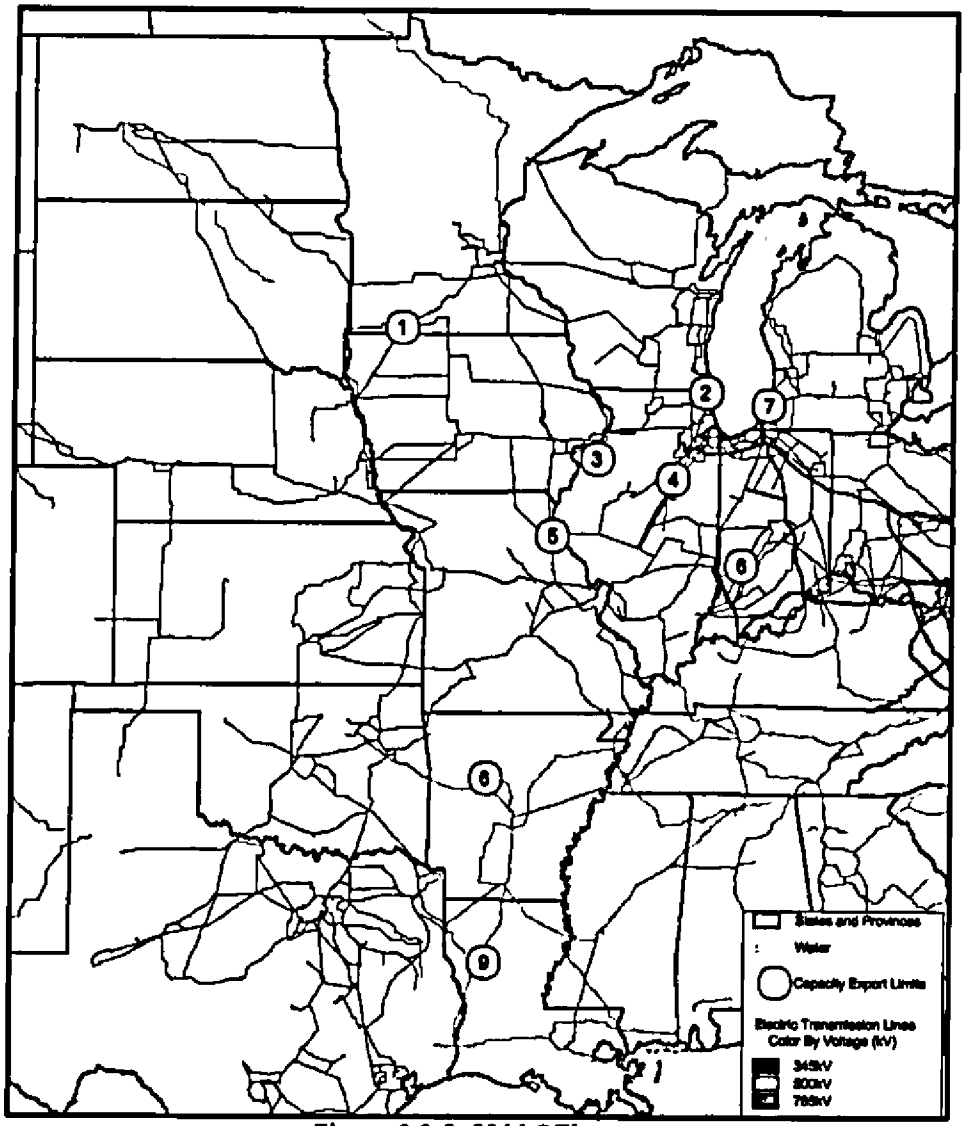


Figure 3.3-2: 2014 CEL map

3.3.1 Out-Year (2018 and 2023)

This is the first LOLE PRM study that contains out-year transfer analyses, and targets the years 2018 and 2023. The goal of providing this information is for long-term planning purposes. Out-year constraints will be considered in the development of the MISO Transmission Expansion Plan and presented at Sub-Regional Planning Meetings. These results may indicate how changes in available capacity and the transmission system impact CELs, CILs and Local Clearing Requirements (LCR).

The transfer study methodology for the near-term and out-year studies are the same, except redispatch is not applied in the out-year studies since they are indicative of limits the LOLEWG may see in the future.

The 2018 out-year scenario included MTEP Appendix A projects through MTEP12 with in-service dates by July 15, 2018. Impactful projects include Multi-Value Projects that are estimated to be in service within this time frame. The projects highlighted in yellow in Figure 3.3-3 are in service in 2018.

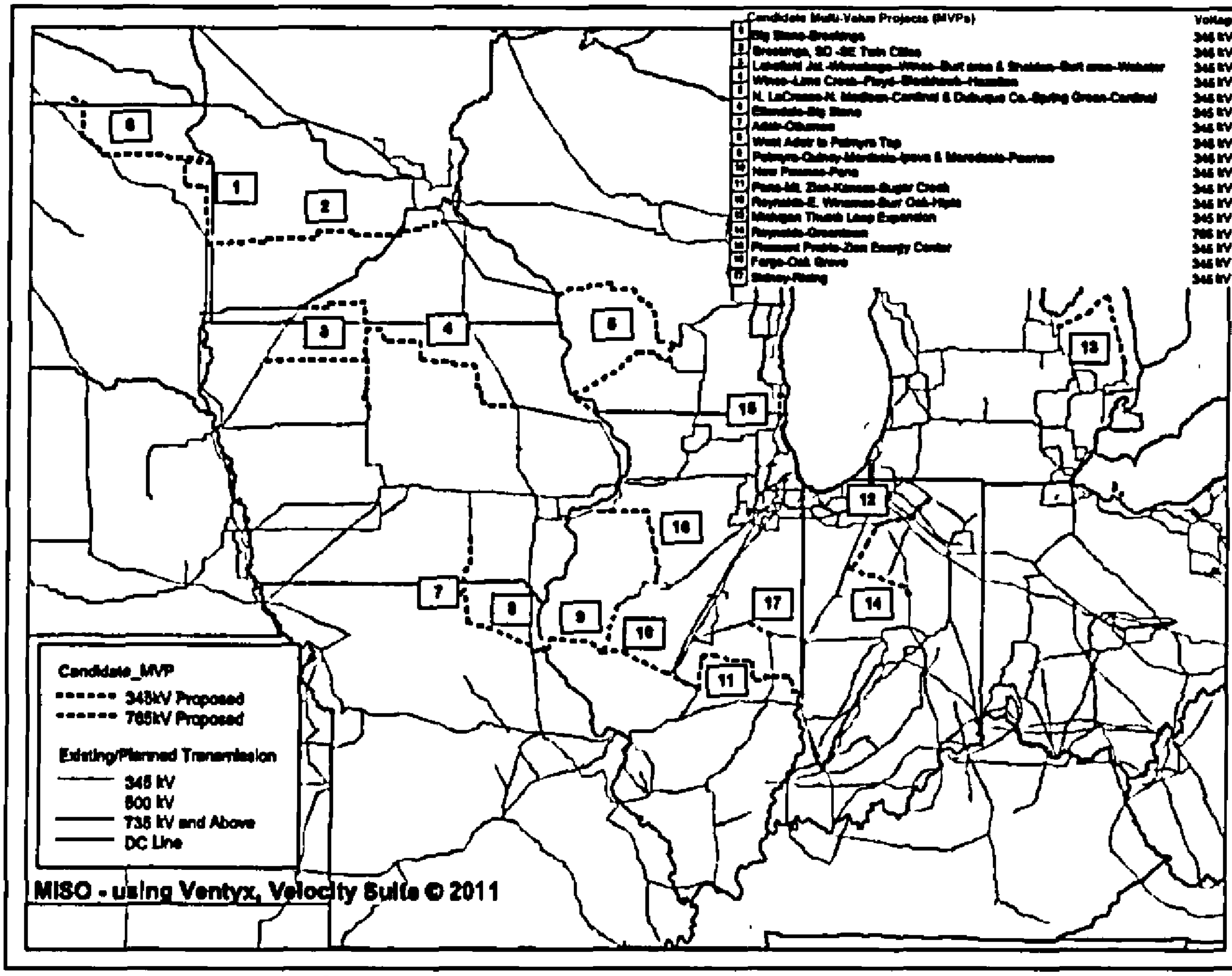


Figure 3.3-3: MVPs in service in the 2018 out-year scenario

Out-year 2018 CIL were originally presented at the September 16, 2013, LOLEWG meeting. Import Limits for zones 2, 3 and 6 were updated in the October 2, 2013, LOLEWG meeting. On October 4, the LOLEWG was informed of updated limit calculations, which were made due to the inadvertent exclusion of certain data. The details are also posted with the October 2, 2013, LOLEWG meeting materials. Table 3.3-3 summarizes the 2018 CIL and the detailed results are in the Appendix.

Zones	Tier	2018 Limit (MW)	Monitored Element	Contingent Element	Figure 3.3-4 Map ID
1	2	3,551	Lime Creek – Worth County 161 kV	Adams – Mitchell County 345 kV	1
2	1	2,437	Turkey River – Stoneman 161 kV	Seneca – Genoa 161 kV	2
3	2	5,985	Sub 3456 – Nebraska City 345	Sub 3455 – Sub 3740 345 kV	3
4	2	11,662	No transmission limit - value reflects generation in Tiers 1 & 2 plus base import		N/A
5	2	3,465	White Bluff – Keo 500 kV	Sheridan – Mabelvale 500 kV	4
6	1	4,874	Wheatland – Petersburg 345 kV	Jefferson – Rockport 765 kV	5
7	2	2,922	Zion Station – Zion Energy Center 345 kV	Pleasant Prairie – Zion 345 kV	6
8	1	1,110	Winnfield – Jeld Wen 115	Hartburg – Mt Olive 500 kV	7
9	1	3,972	Dodson – Jeld Wen 115 kV	Hartburg – Mt Olive 500 kV	7

Table 3.3-3: 2018 Capacity Import Limits

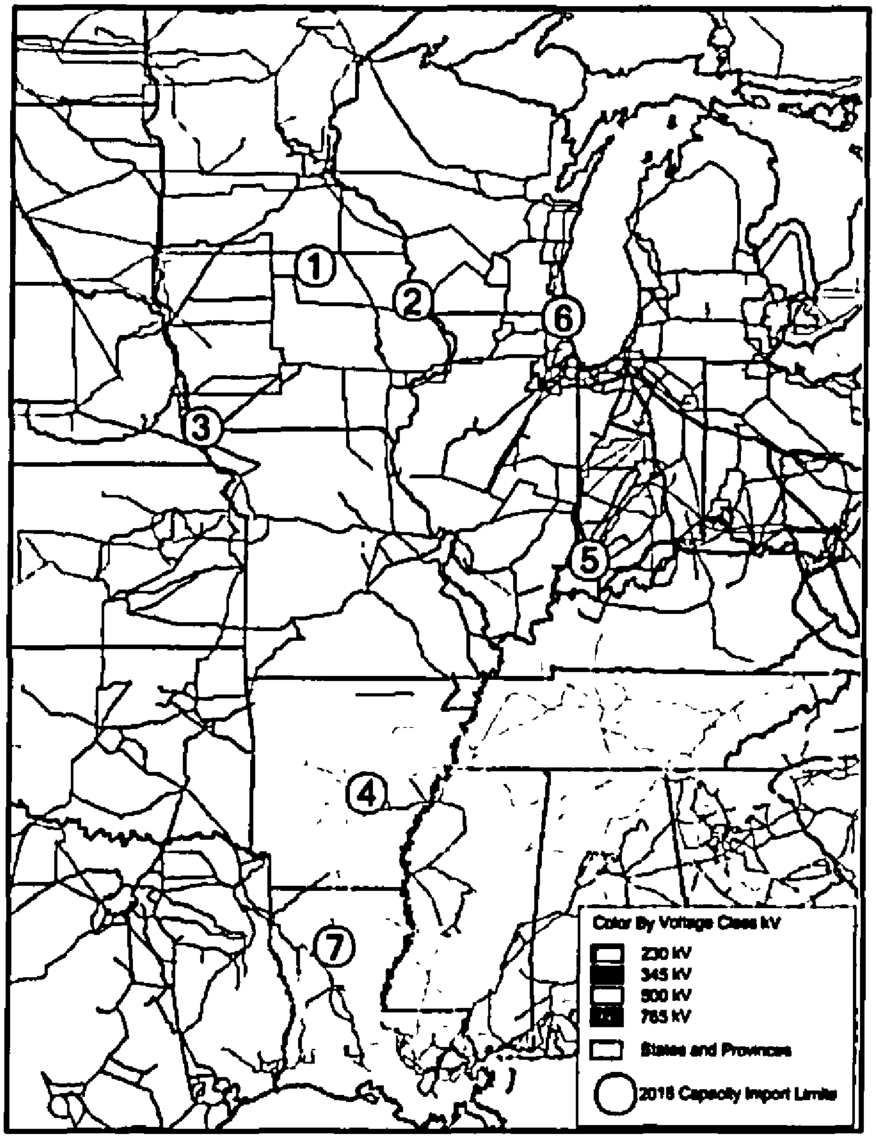


Figure 3.3-4: 2018 CIL map

Out-year 2018 CEL were originally presented in the October 2, 2013, LOLEWG meeting. Updated results were provided on October 4, 2013, and remaining updates were presented at the October 21, 2013, LOLEWG meeting. Similar to the 2014 results, tiers were not considered for 2018 export scenarios. Table 3.3-4 summarizes the 2018 CEL.

Zones	2018 Limit (MW)	Monitored Element	Contingent Element	Figure 3.3-5 Map ID
1	2,499	Briggs Rd – Mayfair 161 kV	Briggs Rd – LaCrosse – Genoa 161 kV	1
2	1,582	Zion Station – Zion Energy Center 345 kV	Pleasant Prairie – Zion 345 kV	2
3	2,983	Cordova – Nelson 345 kV	Quad Cities – H471 345 kV	3
4	3,010	No transmission limit – value reflects available generation in zone plus base export		N/A
5	2,181	No transmission limit - value reflects available generation in zone plus base export		N/A
6	1,639	Lafayette – Tricounty 230 kV	Cayuga – Frankfort 230 kV and Frankfort 230/69 kV transformer	4
7	4,813	Benton Harbor 345/138 kV transformer	Benton Harbor – Cook 345 kV	5
8	2,180	Butterfield (Woodlawn Rd) – Haskell 115 kV	Sheridan - Mabelvale 500 kV	6
9	2,295	Winnfield 230/115 kV	Montgomery - Clarence 230 kV	7

Table 3.3-4: 2018 Capacity Export Limits

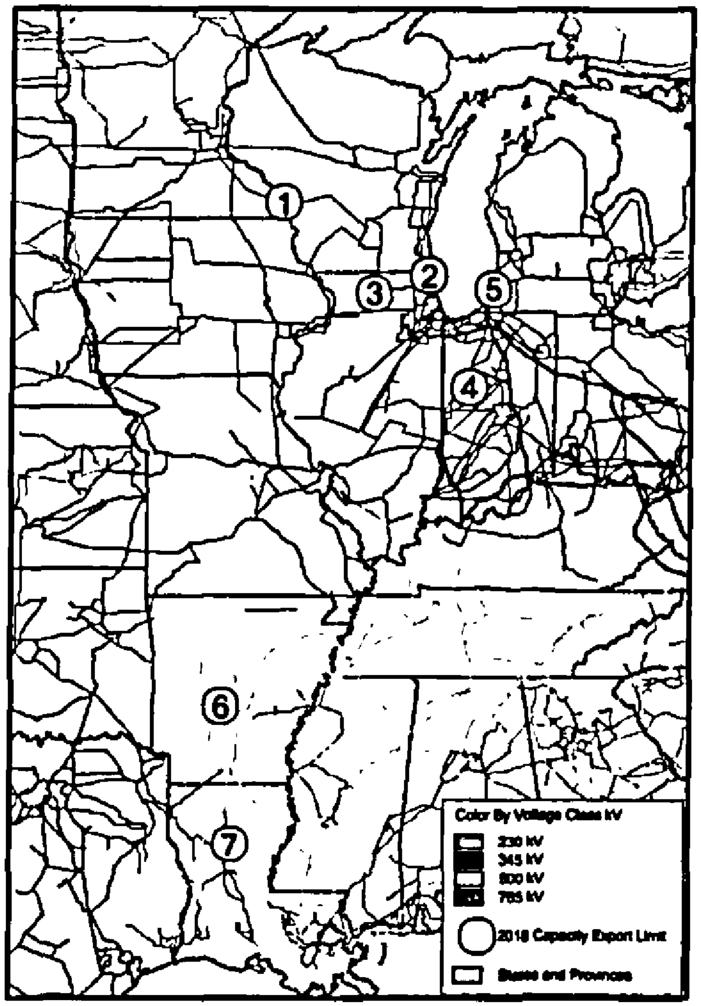


Figure 3.3-5: 2018 CEL map

The 2023 out-year scenario included MTEP Appendix A projects with in-service dates by July 15, 2023. A more detailed review of the 2023 model was required due to generation assumptions in 10-year-out planning models for external areas. Through the review, additional generation without associated transmission facilities was found in the ComEd Co., Louisville Gas and Electric Co. and Tennessee Valley Authority systems. MISO believes that through increased interregional coordination through the FERC 1000 effort it will be able to expedite the out-year model review in the future. Also, as documented as a future improvement, MISO intends to start more in-depth coordination with external areas at the onset of the study.

Out-year 2023 CIL was originally presented in the October 2, 2013, LOLEWG meeting for a subset of zones. Remaining limits and updates were presented at the October 21, 2013, LOLEWG meeting. Table 3.3-5 summarizes the 2023 CIL and the detailed results are in Appendix C: Transfer Analysis.

Zones	Tier	2023 Limit (MW)	Monitored Element	Contingent Element	Figure 3.3-6 Map ID
1	1	2,805	Lime Creek – Worth County 161 kV	Adams – Mitchell County 345 kV	1
2	1	1,257	Lockport – Kendall 345 kV blue circuit	Lockport – Kendall 345 kV red circuit	2
3	1	1,017	Maywood – Spencer 345 kV	Meredosia – Pawnee 345 kV	3
4	2	11,339	No transmission limit - value reflects generation in Tiers 1 & 2 plus base import		N/A
5	1	4,278	Perryville – Grand Tower 138 kV	Grand Tower – Campbell Hill Jct – Steeleville 138 kV	4
6	1	4,514	Benton Harbor 345/138 kV transformer	Benton Harbor – Cook 345 kV	5
7	2	253	Dequine – Meadow Lake 345 kV circuit 2	Dequine – Meadow Lake 345 kV circuit 1	6
6	1	1,094	Winnfield – Jeld Wen 115	Hartburg – Mt Olive 500 kV	7
9	1	4,050	Coly 500/230 kV transformer	Fancy Point 230/500 kV transformer	8

Table 3.3-5: 2023 Capacity Import Limits

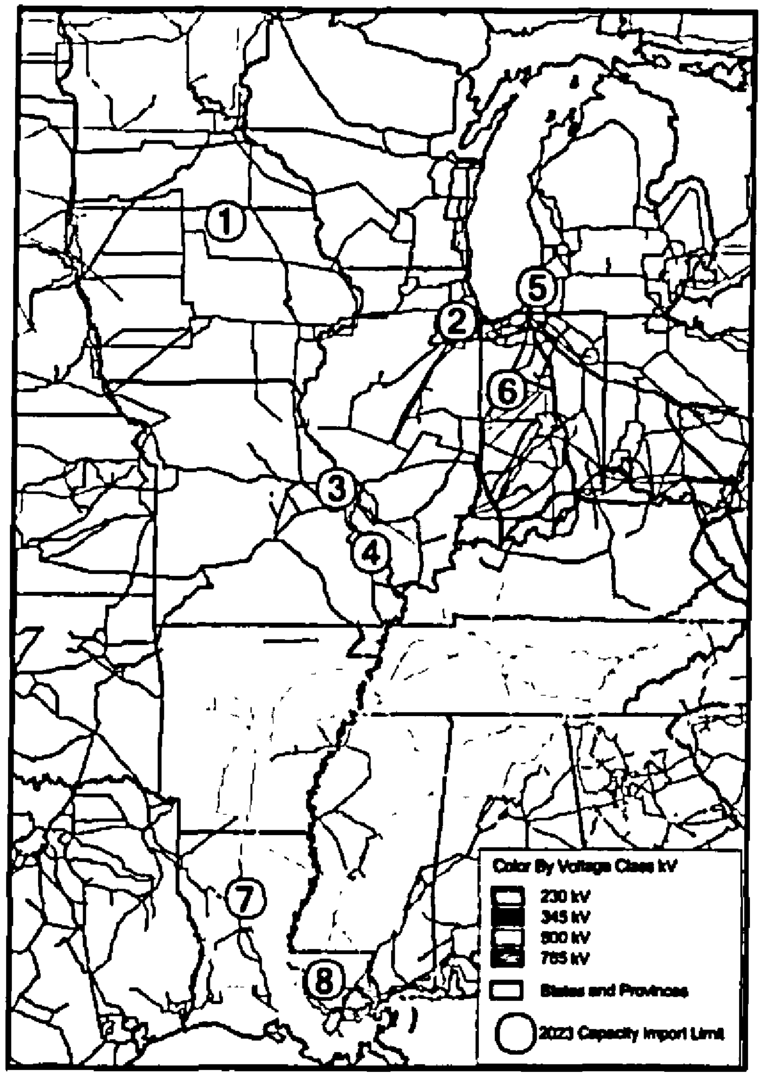


Figure 3.3-6: 2023 CIL map

The out-year limit tables will be presented at the appropriate sub-regional planning meetings. It will then be determined if further analysis is required.

The 2023 constraint for Zone 3's CIL was not identified as limiting for any other transfer and is significantly more limiting than 2018's constraint. The main difference between the 2018 and 2023 scenario causing this difference is generation dispatch specific to that area. Several hundred megawatts of generation dispatched in the 2023 model that interconnected in the area of the constraint were offline in the 2018 model.

Zone 7's 2023 CIL is significantly more limiting than 2018. The constraint is in PJM's system and has been identified in prior MISO studies including MTEP13 NERC Transmission Planning (TPL) analyses. The monitored element is approaching its limit in 2018 and 2023 without the transfer. It was not identified as the limiting constraint in 2018 because the base flow is less than 2023; however in 2018 the post-contingent flow is still approaching the limit. One major difference between the 2018 and 2023 power flow models that could be causing the base flow differences is generation dispatch level in Zone 7, which is much higher in 2023. This causes Zone 7 to be an exporter, while it is an importer in 2018. Only one additional generator was found in the 2023 model, so the additional dispatch was primarily due to increases in dispatch of units offline in 2018 and online in 2023.

A potential improvement for subsequent studies is for MISO to provide model summaries by zone or area. The intent of the summary is to aid in the identification of modeling concerns by the reviewing transmission owner. This improvement will identify modeling concerns early in the study so they can be resolved before final posting of the report, which will ensure the appropriate constraints are reviewed in the Sub-Regional Planning Meetings.

Out-year 2023 CEL was originally presented in the October 2, 2013, LOLEWG meeting for a subset of zones. Remaining limits and updates were presented at the October 21, 2013, LOLEWG meeting. Table 3.3-6 summarizes the 2023 CEL and the detailed results are in the Appendix C: Transfer Analysis.

Zones	2023 Limit (MW)	Monitored Element	Contingent Element	Figure 3.3-7 Map ID
1	1,203	No transmission limit - value reflects available generation in zone plus base export		N/A
2	1,199	No transmission limit - value reflects available generation in zone plus base export		N/A
3	3,462	No transmission limit - value reflects available generation in zone plus base export		N/A
4	1,808	Loretto – Wilton 345 kV	Pontiac – Dresden 345 kV	1
5	1,771	No transmission limit - value reflects available generation in zone plus base export		N/A
6	1,020	No transmission limit - value reflects available generation in zone minus base import		N/A
7	3,895	Plano - Electric Jct. 345 kV blue circuit	Plano - Electric Jct. 345 kV red circuit	2
8	284	Russelville North - Russleville East 161 kV	Arkansas Nuclear One - Ft. Smith 500 kV	3
9	321	Russelville East - Russleville South 161 kV	Arkansas Nuclear One - Ft. Smith 500 kV	3

Table 3.3-6: 2023 Capacity Export Limits

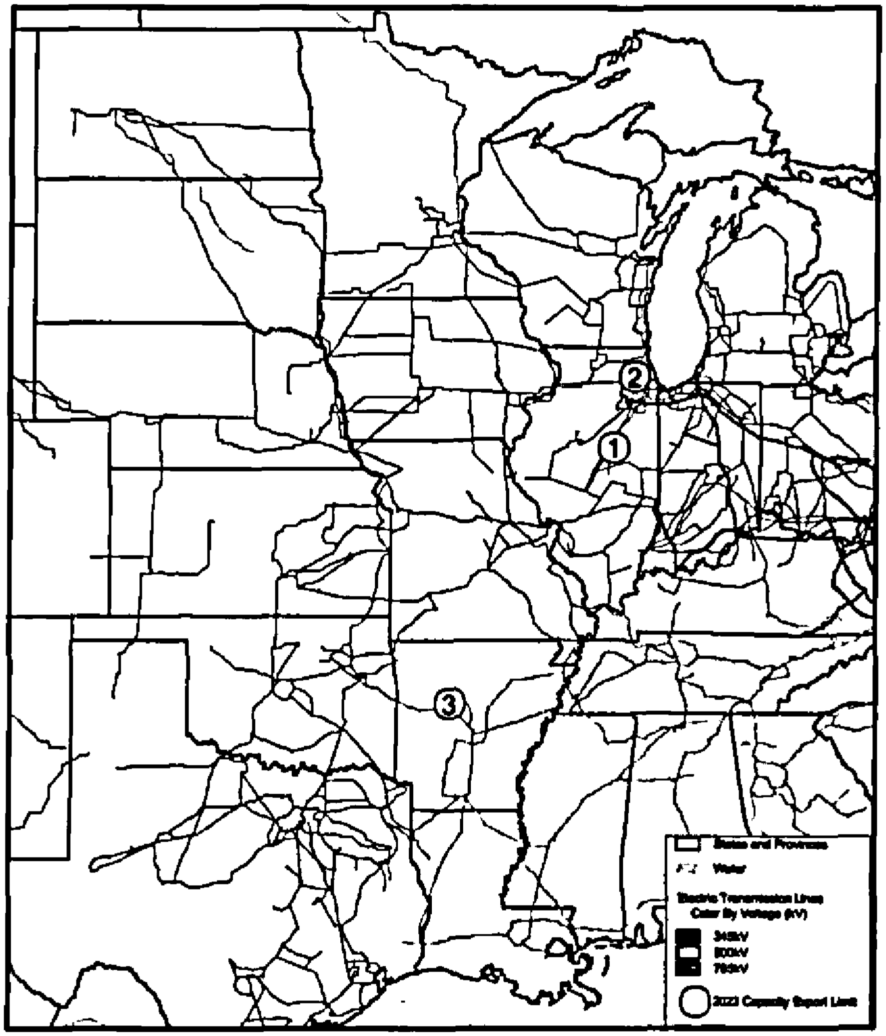


Figure 3.3-7: 2023 CEL map

4 Loss of Load Expectation (LOLE) Analysis

4.1 LOLE Modeling Input Data and Assumptions

MISO utilizes a program developed by General Electric called Multi-Area Reliability Simulation (MARS) to calculate the LOLE for the applicable planning year. GE MARS uses a sequential Monte Carlo simulation to model a generation system and assess the system's reliability based on any number of interconnected araas. GE MARS calculates the annual LOLE for the MISO system and each Local Resource Zone (LRZ) by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, load forecast uncertainty and external support.

The GE MARS model builds are the most time-consuming tasks of the Planning Reserve Margin (PRM) study. Many cases are built to model different scenarios and to determine how certain variables impact the results. The base case models determine the MISO PRM_{ICAP}, PRM_{UCAP} and the Local Reliability Requirements (LRR) for each LRZ for years one, five and 10.

4.2 MISO Generation

4.2.1 MISO Midwest

Thermal Units

MISO's PowerGADS is the source for much of the data used in the PRM study. PowerGADS provides unit specific information such as:

- Generator Verification Test Capacities (GVTC)
- Monthly Net Dependable Capacities (NDC)
- Unit Forced Outage Rates (EFORd and XEFORd as defined by IEEE 762)
- Planned Maintenance Factor (average number of events and duration)

Thermal units are only included in the study if they have a Commercial Pricing Node (CPNode) (March 2013 Commercial Model) and are not on a long-term outage. The GVTC values, along with the monthly NDC values, are used to determine the capacity profile for each unit except in cases where a unit is new to the commercial model. New units used the commercial model Pmax value for each month's capacity. The utility submitting the data into MISO's PowerGADS along with the CPNode associated with each unit help determine which LRZ the unit should be included.

Forced outage rates and planned maintenance factors were calculated over a five-year period (January 2008 to December 2012) and modeled as one value. Some units did not have five years of historical data in PowerGADS, but if they had at least 12 months of data then unit-specific information was used. If a unit had less than 12 months of unit-specific data in PowerGADS, then that unit was assigned the corresponding MISO class average forced outage rate and planned maintenance factor. If a particular MISO class had less than 30 units, then a North American Electric Reliability Corp. (NERC) class average forced outage rate was used.

Nuclear units have a fixed maintenance schedule, which was pulled from Ventyx PowerBase and was modeled for each of the study years.

Sales

This year's LOLE analysis incorporated firm sales to PJM. For units with capacity being sold to PJM, the monthly capacities were reduced by the megawatt amount being sold. This totaled 2,721 MW for Planning Year 2014-2015 and 2,877 MW for Planning Years 2018-2019 and 2023-2024.

Attachment Y

Generating units that have filed suspensions or retirements (as of June 5, 2013) through MISO's Attachment Y process and have been approved are accounted for in the LOLE analysis. Future retirement and suspension dates are added to the model and the unit was retired or suspended as of the Attachment Y date. Suspensions coming back online during the study period were also accounted for with an installed date set at the suspension end date.

Future Generation

Future thermal generation and upgrades were added based on unit information in the MISO Generator Interconnection Queue. Only units with a signed interconnection agreement (as of July 1, 2013) were included in the LOLE model. These new units were assigned class average forced outage rates and planned maintenance factors based on their particular unit class. Units that were upgraded during the study period reflected the MW increase for each month beginning the month the upgrade was finished. Future wind generation was not included in the LOLE analysis.

Intermittent Resources

Intermittent resources such as run-of-river hydro, biomass and wind were explicitly modeled as demand-side resources. Non-wind intermittent resources such as run-of-river hydro and biomass provide MISO with up to 15 years of historical summer output data during hours ending 15:00 EST through 17:00 EST. This data is averaged and modeled in the LOLE analysis as unforced capacity for all months. Each individual unit is modeled and put in the corresponding LRZ.

Each wind-generating CPNode received a capacity credit based on its historical output from MISO's top eight peak days in past years. The megawatt value correlating to each CPNode's wind capacity credit was used for each month of the year. If a unit was new to the commercial model and did not receive a wind capacity credit as part of the 2013 Wind Capacity Credit analysis, then that unit was given the MISO-wide wind capacity credit of 13.3 percent as established by the 2013 Wind Capacity Credit Effective Load Carrying Capability (ELCC) analysis. The capacity credit established by the ELCC analysis determines the maximum percent of the wind unit that can receive credit in the PRA while the actual amount could be less. This value was applied to the maximum capacity value in the commercial model and used for all months in the year. Aggregate megawatt values for wind generating units are then determined for MISO and each LRZ. The detailed methodology for establishing the MISO-wide and individual CPNode Wind Capacity Credits can be found in the 2013 Wind Capacity Credit Report.

Load Modifying Resources

Behind-the-meter generation and demand response data came from the Module E Capacity Tracking (MECT) tool. These resources were explicitly modeled as energy-limited resources. Behind-the-meter generation is modeled as monthly unforced capacity with a monthly energy and aggregated by LRZ.

Each demand response program was modeled individually with a monthly capacity and energy, which is limited to the number of times each program can be called upon as well as limited by duration.

4.2.2 MISO South

The 2014-2015 planning year LOLE analysis incorporated MISO South for the first time, as that region will fully integrate into MISO in December 2013. MISO South companies were asked to submit up to five years (January 2008 to December 2012) of data into MISO's PowerGADS. For the companies that submitted at least 12 consecutive months of data ending with December 2012, unit-specific information was used in the LOLE model. Approximately 80 percent of the MISO South units used unit-specific information and the other 20 percent received class average forced outage rate and planned maintenance factors.

Summer installed capacity values that were submitted into PowerGADS along with NDC values were used to determine the monthly profiles for each unit. If a unit did not submit any information into PowerGADS, then the summer installed capacity value was assumed for all months.

In future years, MISO expects to more accurately model MISO South units with actual unit-specific GVTC and forced outage rate information for nearly all of MISO South. Also, behind-the-meter generation and demand response will be modeled in future years because that information will be submitted in the MECT tool. This information was not available at the time of the 2014-2015 LOLE analysis.

4.3 MISO Load Data

For the 2014-2015 LOLE analysis, the hourly LRZ load shape was a product of the historical load shape used as well as the 50/50 demand forecasts submitted by Load Serving Entities (LSE) through the MECT tool. Demand forecasts for MISO South were pulled from Ventyx PowerBase since the data was not available to MISO at the time of the analysis. In future years, the LOLE analysis will utilize demand forecasts submitted through the MECT tool for all of MISO.

The non-coincident peak demand forecasts (with transmission losses) by LSEs were aggregated by their respective Local Balancing Authorities (LBA) and applied to the LBA's historical load shape in GE MARS. LRZs 1 through 7 used the 2005 historical load shape while zones 8 and 9 used the 2006 historical load shape. For MISO Midwest, the 2005 load shape provides a typical load shape for the Midwest region as well as inherent conservative external support due to external load shapes. With the integration of MISO South, MISO chose to use the 2006 historical shape as the 2005 shape represented an extreme weather year for the South region due to Hurricane Katrina. In GE MARS, MISO utilized the ability to input monthly peaks, which MARS used to modify the historical load shape accordingly in order to adhere to the monthly peak forecasts that LSE's submitted. These are shown as the MISO System Peak Demand in Table 5.1-1 and LRZ Peak Demand in Table 6.1-1.

Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load.

4.3.1 Load Forecast Uncertainty

Load Forecast Uncertainty (LFU), a standard deviation statistical coefficient, is applied to base 50/50 load forecast to represent the various probabilistic load levels. With transition into Module E1 in 2012, MISO determines two separate requirements: Local Reliability Requirement (LRR) for each zone as well as an overall MISO-wide Planning Reserve Margin (PRM).

- In 2012, MISO began calculating LFU for each Local Resource Zone (LRZ) to derive the LRR by applying the NERC Bandwidth Method to associated zonal historic demand.
- In addition to that, a MISO-wide LFU was calculated and applied to an aggregate MISO load shape to determine a MISO-wide PRM. In the current LOLE study, enhancements were made to this LFU determination.

Through this year's analysis results, it was determined that aggregating the MISO-wide footprint (including MISO South) into one load shape was no longer prudent in derivation of the MISO-wide PRM given the large geographic footprint. This is because a MISO-wide LFU applied to every load in MISO, regardless of its unique LFU and geographic location, misrepresents the local uncertainty in demand. The misrepresentation of local uncertainty in demand is amplified when applying the old method to such a large geographic area.

Historically, LFU for the MISO Midwest region had been around 4 percent; this year an LFU of 3.8 percent was calculated for this region. However, with the addition of MISO South companies, the LFU calculated using the old approach of aggregation into one load shape resulted in about a 3 percent MISO-wide LFU. Due to cancelation effects, the overall uncertainty is inherently dampened with the older approach as two large geographic areas with seemingly different weather patterns combine. Lower procured capacity results from statistically derived lower aggregation, which misrepresents reliability need in different parts of the system unique to those geographic regions.

MISO identified a new modeling technique, which connected each Local Resource Zone to a central hub with infinite ties. This enabled MISO to model each LRZs demand and generation uniquely. Use of this method to derive the MISO-wide PRM better aligns with the zonal construct. The resulting LFU through modeling in a probabilistic model was determined to be 3.9 percent for the aggregate MISO footprint, which is in line with previously derived LFU. Further details of this determination are discussed later in this section. The 3.9 percent compares closely with previously established LFUs by NERC for its Regional Entity's respective footprints. The LFU for ReliabilityFirst Corp. (RFC) was 5.0 percent; SERC Reliability Corp. (SERC) was 3.3 percent, and Midwest Reliability Organization (MRO) was 4.6 percent.

The new method ensures that Local Resource Zone Local Reliability Requirement is established in sync with MISO-wide PRM using the same model and applying the same zonal LFUs. Modeling the more granular zonal LFU values appropriately applies each LRZ's LFU to that LRZ's load, which was not previously captured by applying one MISO LFU value for each LRZ. This application of LFU more accurately reflects the uncertainty impacts of each LRZ's geographic area.

In this new methodology, MARS applied the LFU of each LRZ to its corresponding hourly load; this application was not limited only to the peak loads. In other words, at every specific hour in the model, if one LRZ was taken away from its 50/50 load of that hour by one standard deviation (sigma), all other zones were one sigma away from their 50/50 loads of that very same hour, where the sigma value was a different value of LFU for each LRZ. The LRZ LFU values used in the MISO PRM analysis are provided in Table 4.3-1.

MISO compared this year's methodology and that of previous years. In this comparison, MISO applied one common LFU value to every zone using this year's method and applied the same LFU value to the overall MISO system in the old methods. Then, the 50/50 load was driven away by three standard deviations in each method and verified that the results of both methods were the same. In other words, MISO validated that MARS does not treat a model with zonal LFU any different from a model with a single system wide LFU; as long as the LFU values are all set to be the same.

Zones	LFU
LRZ 1	2.9%
LRZ 2	4.5%
LRZ 3	3.0%
LRZ 4	4.7%
LRZ 5	4.4%
LRZ 6	3.5%
LRZ 7	5.3%
LRZ 8	5.0%
LRZ 9	3.2%

Table 4.3-1: 2014 Local Resource Zone LFU

As discussed previously, MISO back-calculated the system wide LFU equivalent to MISO's current zonal methodology to be about 3.9 percent. In this calculation, the 50/50 hourly load of each LRZ was increased by one standard deviation and then aggregated up to get to one hourly load for the MISO footprint. This load was compared to the 50/50 MISO hourly load and the overall LFU for every hour was calculated. The average of these hourly MISO LFUs was about 3.9 percent. This calculation showed that the MISO Midwest LFU in the old method (3.8 percent) is almost the same as what their effective LFU is in the new methodology (3.9 percent). This also validated MISO's belief that it was unrealistic to reduce the MISO Midwest LFU as a result of MISO South integration, knowing the fact that transmission limits exist between the two regions.

MISO also performed LFU sensitivity analysis to examine its effect on the Planning Reserve Margin Requirement. Figure 4.3-1 shows the LOLE analysis for MISO with varying LFUs and their corresponding PRMs. These cases were studied for the MISO system as an island with no ties to the external world. MISO concludes that for the LFU ranges of 3 percent to 4 percent, a 1 percent increase in LFU contributes to an increase of about 2 percent in PRM_{UCAP}.

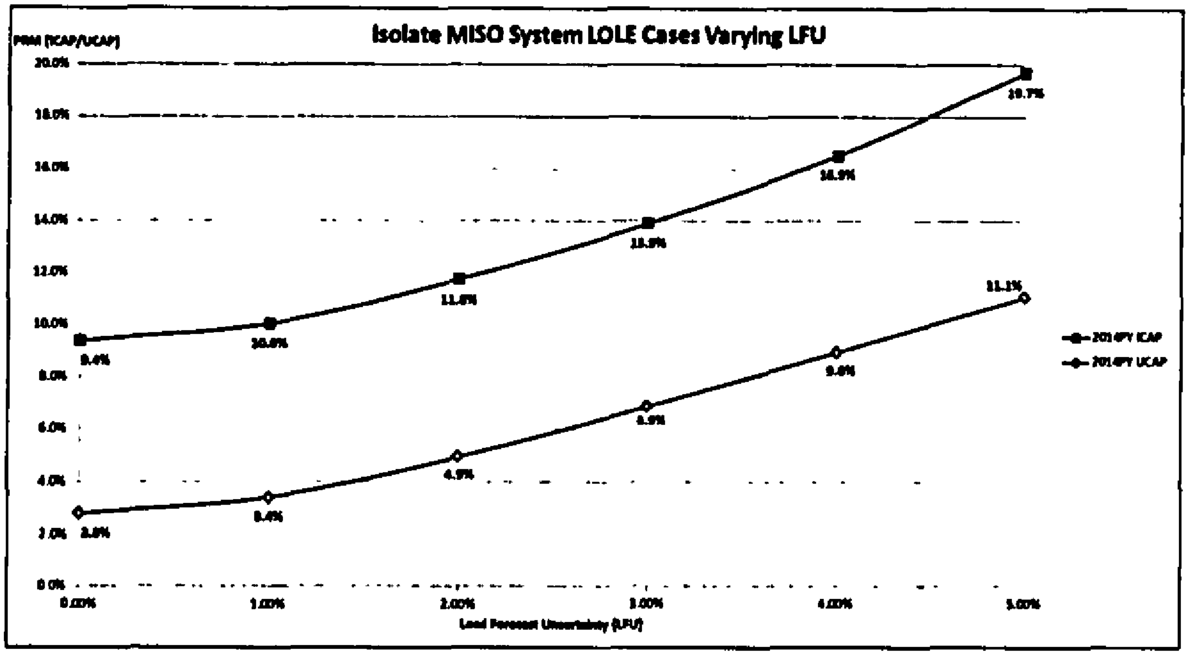


Figure 4.3-1: MISO system with varying LFU

Going forward, MISO will start an LFU task force/team to discuss improvement areas for LFU calculation such as:

- Capturing the weather uncertainty portion of LFU as well as the weather correlation between zones
- Enhance MARS to do Monte Carlo simulation for load based on uncertainty correlation between zones
- Connecting LFU with different futures

More details about the LFU methodology are provided in Appendix A: Load Forecast Uncertainty.

4.4 External System

The 2014 LOLE study made several enhancements to the external system modeling compared to the 2013 study methodology while still maintaining the general framework. The LOLE study utilized an external model with seven external zones. In order to determine an appropriate level of support that MISO could expect from the external systems, each external zone was modeled at its appropriate target PRM with adjustments for sales/purchases and demand-side management (DSM) program reductions. The tie capacity value to each external zone was derived from an analysis of the 2012 Historical Net Scheduled Interchange (NSI) data. MISO South companies provided the NSI data separately since they had not integrated into MISO at the time of the LOLE study. This data was merged with the MISO Midwest NSI data to determine the total tie capacity values to each external zone. The LOLE model probabilistically determines reasonable external assistance and reduction in the PRM from being interconnected to external entities.

4.4.1 Development of the External Model Import Tie Capability

The total tie limits for the external model were derived from observing the hourly historical maximum NSI between MISO and each first-tier balancing authority (BA) during NAESB designated summer peak hours. NAESB summer peak hours are defined as 0800 to 2300 EST Hour Ending, Monday through Saturday, and in the months June through August. Previous LOLE studies determined NSI values over the entire year. The move to summer peak hours more accurately reflects available external support in a MISO peak demand scenario when a loss of load event is most likely to occur. The 2012 NSI data was analyzed for the 2014-2015 LOLE analysis. The 17 first-tier BA's historical NSI values were merged into seven equivalent external zones that would mirror limits to adjacent Regional Transmission Operators (RTO), power pools, or Reliability Coordinators. Figure 4.4-1 shows the BA breakdown of these seven external zones and further breaks down the external purchases coming into MISO by LRZ. When determining the MISO PRM, all external purchases are modeled as firm non-curtailable contracts from the respective external zone to MISO. MARS will account for the firm contracts when calculating available flow on the tie lines. In the LRZ LRR model, external purchases are not modeled as the zone is treated as an island. The UCAP values shown in Table 6.1-1 only reflect generation that is internal to that zone and does not account for generation claimed from outside MISO.

External Zone Number	External Resources (MW)	NERC Acronym	Prevailing 2012 17 MISO 1st Tier Balancing Authorities Reflecting 2014 Footprint
Zone 1	405.7	WAUE	Western Area Power Administration – UGPR East
Zone 2	1,403.2	MHEB	MHEB, Transmission Services
		SPC	SaskPower Grid Control Centre
Zone 3	529.7	PJM	PJM Interconnection
Zone 4		ONT	Ontario - Independent Electricity System Operator
Zone 5		WR	Westar Energy/Missouri Joint Municipal Electric Utility Commission
	24.9	SPA	Southwestern Power Administration
	14.2	SPP	Southwest Power Pool (includes other SPP BAs of NPPD, OPPD, and LES)
		CSWS	AEPW - American Electric Power Company West (formerly Central and South West Services)
		OKGE	Oklahoma Gas and Electric Company
		EDE	Empire District Electric
		SECI	Sunflower Electric
Zone 6		SOCO	Southern Company Services, Inc.
Zone 7	114.0	LGEE	Louisville Gas and Electric
	218.0	TVA	Tennessee Valley Authority ESO
	393.6	EEI	Electric Energy, Inc.
		AEC	Appalachian Electric Coop.
		AECI	Associated Electric Cooperative, Inc.
Total	3,103.3		

Figure 4.4-1: MISO first-tier Balancing Authorities with external purchases

Figure 4.4-2 summarizes the maximum hourly import and export schedules to each of the seven external zones. The "MISO Coincident" column represents the coincident summation of the seven external zones, and therefore represents the overall MISO NSI. The study does not utilize the export values indicated by the black bars.

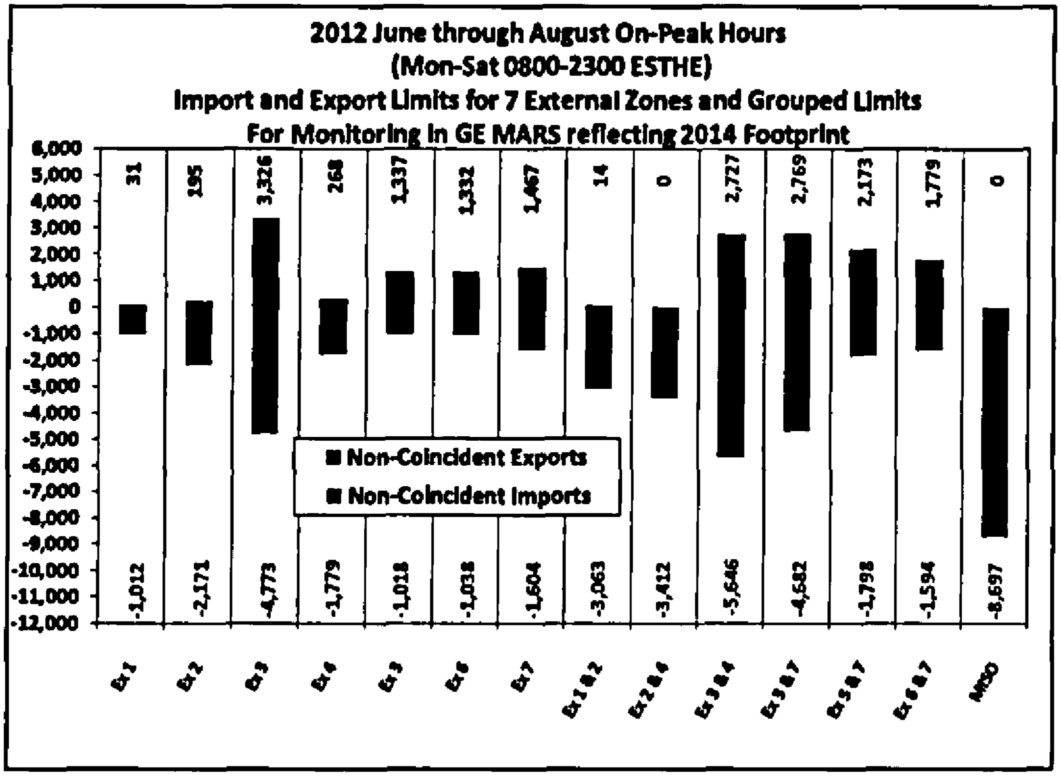


Figure 4.4-2: 2012 Net Scheduled Interchange (NSI) – summer peak hours

4.4.2 External Zones Base PRM and Adjustments

For the external zones, all load and generator data came from vendor-supplied databases since MISO only collects detailed information on MISO load and generation resources. MISO then set the available generation for each external zone at its reported planning reserve margins. If a regional PRM was not established, MISO used the NERC reference margin of 15 percent. The target PRM was then increased by external purchases. External purchases are external resources claimed in MECT for the 2013-2014 Planning Year. In the 2013 Planning Resource Auction, the declared external resources in MECT totaled 3,103 MW. External sales have the inverse relationship to purchases and decreased the external regions target PRM. Only MISO capacity sold in PJM's Reliability Pricing Model (RPM) was modeled. This amount was determined by capacity that cleared in the PJM auction as well as having signed Firm Transmission Service Request (TSR) agreements that begin on or before the 2014-2015 Planning Year. An enhancement from the 2013 LOLE model was the reduction in external DSM availability for MISO emergency assistance. In previous LOLE studies, MISO was able to call on all external DSM programs in times of peak demand. To more accurately model operational characteristics in times of peak demand the external zones corresponding DSM was removed from its available capacity, effectively reducing the target PRM. External zones DSM program data was taken from the 2012 NERC Long-Term Reliability Assessment. Table 4.4-1 itemizes each external zone's base PRM, purchases, sales, and DSM programs by planning year.

External Zone	PRM Base (%)			External Purchases (MW)			External Sales (MW)			External Load Modifying Resources (MW)		
	2014PY	2018PY	2023PY	2014PY	2018PY	2023PY	2014PY	2018PY	2023PY	2014PY	2018PY	2023PY
Ext1-WAUE	15.0%	15.0%	15.0%	406	406	406	-	-	-	135	190	190
Ext2-MHEB	12.0%	12.0%	12.0%	1,403	1,403	1,403	-	-	-	382	510	510
Ext3-PJM	15.9%	15.5%	15.6%	530	530	530	2,721	2,877	2,877	14,004	14,004	14,004
Ext4-IESO	18.6%	20.2%	20.2%	-	-	-	-	-	-	2,950	5,397	5,397
Ext5-SPP	13.6%	13.6%	13.6%	39	39	39	-	-	-	1,672	2,408	2,408
Ext6-SOCO	15.0%	15.0%	15.0%	-	-	-	-	-	-	2,100	2,263	2,263
Ext7-SERC	15.0%	15.0%	15.0%	726	726	726	-	-	-	2,354	3,776	3,776
Total				3,103	3,103	3,103	2,721	2,877	2,877	23,597	28,548	28,548

Table 4.4-1: External Zones PRM Targets

The historic 8,697 MW value shown in Figure 4.4-3 was the maximum coincident import flow in 2012, which sets the limit that the model allows into MISO. Other maximum non-coincident values from each of the external zones are also shown. For example, 1,018 MW is the non-coincident limit from the external zone "Ex 5." Ex 5 is also a merged zone, since it is a zone derived from observing the historical first-tier NSI from six BAs.

Features in the LOLE simulation can simultaneously track the supporting flows up to a zone's individual non-coincident maximum flow from a BA (indicated in red in Figure 4.4-3) and also limit the support amount to a lower level as dictated by the coincident sum combinations (indicated by the grouped coincident values in blue font). The 8,697 MW limit in blue font is the overall MISO coincident limit.

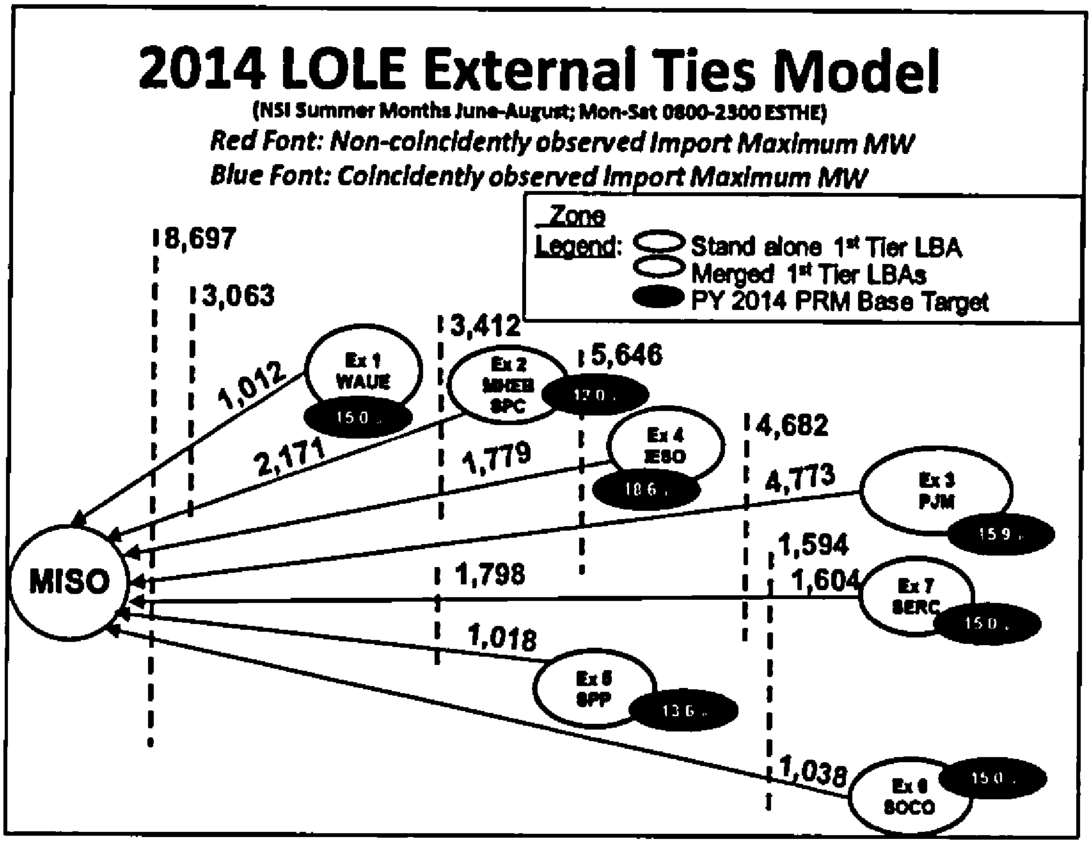


Figure 4.4-3: MISO first-tier Balancing Authorities with external purchases

4.4.3 Loss of Load Expectation Analysis and Metric Calculations

Once the GE MARS input files were created, MISO determined the appropriate PRM_{ICAP} and PRM_{UCAP} for the 2014-2015 Planning Year as well as the appropriate Local Reliability Requirement for each of the nine LRZ's. These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year.

4.4.4 MISO LOLE Analysis and PRM Calculation

For the MISO analysis, generating units were modeled as part of their appropriate LRZ as a subset of a larger MISO pool. The MISO system was modeled with no internal transmission limitations with external transmission ties to MISO's first tier BAs. In order to meet the reliability criteria of 0.1 days per year LOLE, capacity is either added or removed from the MISO pool. The minimum amount of capacity above the 50/50 net internal MISO Coincident Peak Demand required to meet the reliability criteria was used to establish the PRM values.

For the 2014-2015 planning year, MISO had more than enough capacity to meet a LOLE of 0.1 days per year. In order to achieve a LOLE of 0.1 days per year, unforced capacity had to be removed from the MISO pool. This was done following an iterative process of removing the units with the smallest unforced capacity until MISO reached a LOLE of 0.1 days per year. The last unit removed was not completely removed but derated to a point where the reliability criterion was met.

The formulas for the PRM values for the MISO system are:

PRM_{ICAP} = (Installed Capacity + Firm External Support + ICAP Adjustment to meet a LOLE of 0.1 days per year) – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

PRM_{UCAP} = (Unforced Capacity + Firm External Support + UCAP Adjustment to meet a LOLE of 0.1 days per year) – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

Where UCAP = ICAP x (1 – XEFORd)

4.4.5 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the LRZ analysis, each LRZ included only the generating units within the LRZ and was modeled without consideration of the benefit of the LRZ's Capacity Import Limit. Much like the MISO analysis, unforced capacity is either added or removed in each LRZ such that a LOLE of 0.1 days per year is achieved. The minimum amount of unforced capacity above each LRZ's Peak Demand required to meet the reliability criteria was used to establish each LRZ's LRR.

For the 2014-2015 planning year, four LRZs had more than enough capacity to meet a LOLE of 0.1 days per year. In order to determine the LRR for these LRZs, unforced capacity had to be removed. This was done following an iterative process of removing the units with the smallest unforced capacity until the LOLE was 0.1 day per year for the LRZ. Typically, the last unit removed was not completely removed but derated to a point where the reliability criterion was met.

Proxy units of typical size (160 MW) and class average EFORd (5.9 percent) were added to an LRZ when there was not sufficient unforced capacity within the LRZ to achieve the LOLE of 0.1 day per year. A fraction of the final proxy unit was added to achieve exactly the LOLE of 0.1 day per year for the LRZ. Five LRZs were short capacity to meet 0.1 days per year LOLE and needed proxy units added.

The formula for the LRR for a given LRZ (*e.g.*, LRZ_{z1}) is:

LRR_{z1} = (largest Unforced Capacity rated $unit_{z1}$ + 2nd largest Unforced Capacity rated $unit_{z1}$ + 3rd largest Unforced Capacity rated $unit_{z1}$ + ..., including, if necessary, any proxy units) such that the $LOLE_{z1}$ = 0.1 day per year

A per-unit LRR was then calculated because the actual demand forecasts will not be known until the 2014 Planning Resource Auction takes place in April 2014.

The formula for the per-unit LRR for a given LRZ (*e.g.*, LRZ_{z1}) is:

Per-Unit LRR_{z1} = LRR_{z1}/ LRZ_{z1} Peak Demand in Study Model

5 MISO System Planning Reserve Margin Results

5.1 Planning Year 2014-2015 MISO Planning Reserve Margin Results

For the 2014-2015 planning year, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning installed capacity (ICAP) reserve margin of 14.8 percent and a planning unforced capacity (UCAP) reserve margin of 7.3 percent. These PRM values assume 3,103 MW UCAP of firm and 1,899 MW UCAP of non-firm external support. Table 5.1-1 shows all the values and the calculations that went into determining the MISO system PRM_{ICAP} and PRM_{UCAP}.

MISO Planning Reserve Margin (PRM)	2014/2015 PY (June 2014 - May 2015)	Formula Key
MISO System Peak Demand (MW)	125,453	[A]
Time of System Peak (EST)	8/5/2014 17:00	
Installed Capacity (ICAP) (MW)	170,847	[B]
Unforced Capacity (UCAP) (MW)	146,961	[C]
Firm External Support (MW)	3,103	[D]
Adjustment to ICAP (MW)	-29,875	[E]
Adjustment to UCAP (MW)	-15,452	[F]
ICAP PRM Requirement (PRMR) (MW)	144,075	[G]=[B]+[D]+[E]
UCAP PRM Requirement (PRMR) (MW)	134,612	[H]=[C]+[D]+[F]
MISO PRM ICAP	14.8%	[I]=([G]-[A])/[A]
MISO PRM UCAP	7.3%	[J]=([H]-[A])/[A]

Table 5.1-1: Planning Year 2014-2015 MISO System Planning Reserve Margins

5.1.1 Comparison of PRM Targets Across Five Years

Figure 5.1-1 compares the PRM_{ICAP} and PRM_{UCAP} values over the last five planning years. The last endpoints of the black and green lines show the planning year 2014-2015 PRM values.

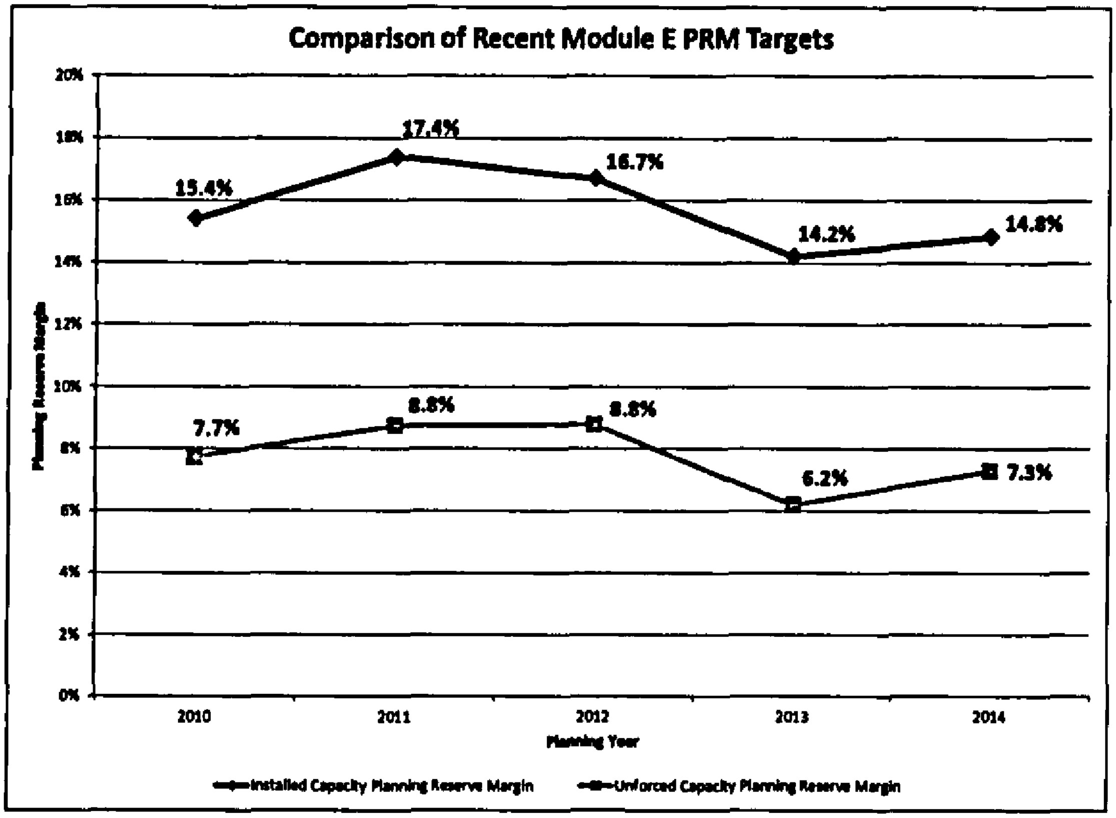


Figure 5.1-1: Comparison of PRM targets across five years

5.2 Future Years 2015 through 2023 Planning Reserve Margins

Beyond the planning year 2014-2015 LOLE study analysis, an LOLE analysis was performed for the five-year-out planning year of 2018-2019 and the 10-year-out planning year of 2023-2024. Table 5.2-1 shows all the values and calculations that went into determining the MISO system PRM_{ICAP} and PRM_{UCAP} values for those years. Those results are shown as the red-font values of Table 5.2-2. The years in between were arrived at through interpolation of the results from the years 2014, 2018 and 2023. Note that the MISO system PRM results assume no limitations on transfers within MISO.

In future years, MISO sees stability in the PRM_{UCAP}, which is driven by MISO's assumption of constant LFU in out years. The increasing characteristic of the PRM_{ICAP} is an outcome of the adjustment methodology sensitivity to installed capacity levels of generation and the removal of units needed to reach 0.1 days per year LOLE target level. Smaller UCAP units, such as Wind and Behind-the-Meter Generation (BTMG), are often the first units removed or last units added in the adjustment. In the future years, fewer and fewer of these units are being removed to reach the target LOLE. Since the difference in the ICAP to UCAP rating of these units is greater than the average unit in the system the PRM_{ICAP} is increasing in the future years.

MISO Planning Reserve Margin (PRM)	2018/2019 PY (June 2018 - May 2019)	2023/2024 PY (June 2023 - May 2024)	Formula Key
MISO System Peak Demand (MW)	129,618	134,345	[A]
Time of System Peak (EST)	8/1/2018 17:00	8/2/2023 17:00	
Installed Capacity (ICAP) (MW)	172,282	172,352	[B]
Unforced Capacity (UCAP) (MW)	148,187	148,252	[C]
Firm External Support (MW)	3,103	3,103	[D]
Adjustment to ICAP (MW)	-26,168	-17,913	[E]
Adjustment to UCAP (MW)	-12,342	-7,093	[F]
ICAP PRM Requirement (PRMR) (MW)	149,217	157,542	[G]=[B]+[D]+[E]
UCAP PRM Requirement (PRMR) (MW)	138,949	144,262	[H]=[C]+[D]+[F]
MISO PRM ICAP	15.1%	17.3%	[I]=([G]-[A])/[A]
MISO PRM UCAP	7.2%	7.4%	[J]=([H]-[A])/[A]

Table 5.2-1: Future Planning Years 2018-2019 & 2023-2024 MISO System Planning Reserve Margins

Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
PRM_{ICAP}	14.8%	14.9%	15.0%	15.1%	15.1%	15.6%	16.0%	16.4%	16.6%	17.3%
PRM_{UCAP}	7.3%	7.3%	7.2%	7.2%	7.2%	7.2%	7.3%	7.3%	7.3%	7.4%

Table 5.2-2: MISO System Planning Reserve Margins 2014 through 2023

6 Local Resource Zone (LRZ) Analysis – LRR Results

6.1 Planning Year 2014-2015 Local Resource Zone (LRZ) Analysis

MISO calculated the per-unit Local Reliability Requirement (LRR) of Local Resource Zone (LRZ) Peak Demand for years one, five and 10 (Table 6.1-1 through Table 6.1-3). The unforced capacity (UCAP) values reflect the unforced capacity within each LRZ and the adjustment to UCAP values are the megawatt adjustments needed in each LRZ so that the reliability criteria of 0.1 days per year LOLE is met. The LRR is the summation of the UCAP end adjustment to UCAP megawatts. The LRR is then divided by each LRZ's Peak Demand to determine the per-unit LRR UCAP. The 2014-2015 per unit LRR UCAP values will be multiplied by the updated demand forecasts submitted for the 2014-2015 Planning Resource Auction to determine each LRZ's LRR.

PY 2014-2015	LRZ-1	LRZ-2	LRZ-3	LRZ-4	LRZ-5	LRZ-6	LRZ-7	LRZ-8	LRZ-9	Formula Key
UCAP (MW)	17,754	15,029	10,191	10,746	8,135	20,400	23,201	11,492	29,985	[A]
Adj. to UCAP (MW) {1d in 10yr}	1,880	-266	428	1,478	2,376	-194	1,614	-3,334	-3,532	[B]
LRR (UCAP)	19,634	14,763	10,619	12,224	10,511	20,206	24,815	8,158	26,453	[C]=[A]+[B]
Peak Demand (MW)	17,733	12,805	9,261	10,345	8,771	18,112	21,547	6,309	23,543	[D]
Time of Peak Demand	7/15/2014 17:00 EST	7/21/2014 16:00 EST	7/23/2014 20:00 EST	8/12/2014 18:00 EST	8/6/2014 17:00 EST	8/15/2014 16:00 EST	7/28/2014 18:00 EST	8/10/2014 18:00 EST	8/11/2014 17:00 EST	
LRR UCAP P.U. of LRZ Peak Demand	110.7%	115.3%	114.7%	118.2%	119.8%	111.6%	115.2%	129.3%	112.4%	[E]=[C]/[D]

Table 6.1-1: Planning Year 2014-2015 LRZ Local Reliability Requirements

PY 2018-2019	LRZ-1	LRZ-2	LRZ-3	LRZ-4	LRZ-5	LRZ-6	LRZ-7	LRZ-8	LRZ-9	Formula Key
UCAP (MW)	17,754	14,627	10,132	11,321	8,135	20,905	23,825	11,492	29,985	[A]
Adj. to UCAP (MW) (1d in 10yr)	2,823	706	1,006	1,118	2,445	-273	1,090	-2,895	-2,857	[B]
LRR (UCAP)	20,577	15,333	11,138	12,439	10,580	20,632	24,915	8,597	27,328	[C]=[A]+[B]
Peak Demand (MW)	18,524	13,720	9,740	10,594	8,882	18,572	21,867	6,498	24,420	[D]
Time of Peak Demand	7/10/2018 17:00 EST	7/31/2018 17:00 EST	7/18/2018 20.00 EST	8/7/2018 18 00 EST	8/1/2018 17:00 EST	8/10/2018 16:00 EST	8/1/2018 18.00 EST	8/12/2018 18.00 EST	8/13/2018 17:00 EST	
LRR UCAP P.U. of LRZ Peak Demand	111.1%	111.8%	114.4%	117.4%	119.1%	111.1%	113.9%	132.3%	111.9%	[E]=[C]/[D]

Table 6.1-2: Planning Year 2018-2019 LRZ Local Reliability Requirements

PY 2023-2024	LRZ-1	LRZ-2	LRZ-3	LRZ-4	LRZ-5	LRZ-6	LRZ-7	LRZ-8	LRZ-9	Formula Key
UCAP (MW)	17,754	14,827	10,132	11,321	8,135	20,905	23,890	11,492	29,985	[A]
Adj. to UCAP (MW) (1d in 10yr)	3,762	1,114	1,556	1,432	2,873	336	1,906	-2,901	-1,457	[B]
LRR (UCAP)	21,516	15,741	11,688	12,753	11,008	21,241	25,796	8,591	28,528	[C]=[A]+[B]
Peak Demand (MW)	19,465	14,043	10,232	10,859	9,266	19,144	22,403	6,745	25,569	[D]
Time of Peak Demand	7/11/2023 17.00 EST	7/31/2023 17:00 EST	7/19/2023 20 00 EST	8/8/2023 18 00 EST	8/2/2023 17.00 EST	8/11/2023 16 00 EST	8/2/2023 18.00 EST	8/13/2023 18 00 EST	8/14/2023 17:00 EST	
LRR UCAP P.U. of LRZ Peak Demand	110.5%	112.1%	114.2%	117.4%	118.8%	111.0%	115.1%	127.4%	111.6%	[E]=[C]/[D]

Table 6.1-3: Planning Year 2023-2024 LRZ Local Reliability Requirements

Appendix A: Load Forecast Uncertainty

A.1 LFU Methodology for Planning Year 2014

Since the North American Electric Reliability Corp. (NERC) load forecasting working group disbanded, MISO adapted the 2011 NERC bandwidth methodology to perform Load Forecast Uncertainty (LFU) analysis and developed regression models similar to NERC. MISO included historical load data (1993-2011) to determine MISO LFU and Local Resource Zone (LRZ) LFU. Starting in the 2014 planning year, MISO South companies were included in the LFU calculation.

Forecasts cannot precisely predict the future. Instead, many forecasts append probabilities to the range of possible outcomes. Each demand projection, for example, represents the midpoint of possible future outcomes. This means that a future year's actual demand has a 50 percent chance of being higher and a 50 percent chance of being lower than the forecast value.

For planning and analytical purposes, it is useful to have an estimate of the midpoint of possible future outcomes, as well as the distribution of probabilities on both sides of that midpoint. Accordingly (similar to NERC), MISO developed upper and lower 80 percent confidence bands. Thus, there is an 80 percent chance of future demand occurring within these bands, a 10 percent chance of future demand occurring below the lower band, and an equal 10 percent chance of future demand occurring above the upper band.

The principal features of the bandwidth methodology include:

1. A univariate time series model in which the projection of demand is modeled as a function of past demand. This approach expresses the current value of the time series as a linear function of the previous value of the series and a random shock. In equation form, the first-order autoregressive model can be written as

$$y_t = a + y_{t-1} + \varepsilon_t$$

2. The variability observed in demand is used to develop uncertainty bandwidths. Variability, represented by the variance $\sigma\varepsilon$ of the historic data series, is combined with other model information to derive the uncertainty bandwidths.

More details about the NERC methodology can be found at NERC Bandwidth Methodology.

A.1.1 Historical Data Used in the Model

For the 2014-2015 planning year, the LFU methodology did not change from the 2013-2014 planning year. However, the major data source used in calculating the LFU changed. Previously, the majority of data was collected from EIA 861 at an annual level whereas for the 2014-2015 planning year the majority of data was collected from Energy Velocity at hourly level. Also, MISO South data was added for the 2014-2015 planning year LFU calculations, which was different from previous years. Table A-1 and A-2 list data sources used for calculation of 2014-2015 LFUs.

Midwest Region	
EV (Energy Velocity*) Data	MISO Data
All Members currently in MISO: 1993-2008	Duke Indiana: 1993-2011
Duke Indiana: 1993-2011	BREC: 2009-11/30/2010
BREC: 1993-11/30/2010	DPC:2009-05/31/2010
DPC:1993-05/31/2010	MEC, MPW:2009-08/31/2009
MEC, MPW:1993-08/31/2009	
MISO Settlements Data	
All Members Currently in MISO 2009-2011	

Table A-1: MISO Midwest historical load data sources

South Region		
EV (Energy Velocity) Data	FERC 714- Part III-Schedule 2	Directly from Entergy
Zone 9 members excluding EES: 1993-2011	Entergy EES 1993-1995	EAI+AECC served by Entergy 1993-2011
EES 2003-2011 EV New Topology		EES 1996-2002

Table A-2: MISO South historical load data sources

For Energy Velocity (EV) datasets, hourly loads were prepared by Ventyx (Energy Velocity) where the base data source for this dataset is FERC 714 form - Part III of Schedule 2. The raw data filed for FERC 714 form - Part III of Schedule 2 is usually reported at the level of a planning area. However, in some cases, several load serving entities (LSE) file their load data together as a single entity, resulting in less load resolution. Where practical, Ventyx separated filed loads into the smaller load entities that have originally filed load data individually using models developed by Ventyx. Available hourly data was in two categories of New Topology and Old Topology. Old Topology data was available from 1993-2008 at the level of Local Balancing Authority (LBA), LSE, or Municipals where the new topology was available from 2003-2011 at the LBA level.

For each of these topologies, the monthly peaks were derived from the LBA/LSE hourly loads. Based on the correlation between old and new topologies, from six years of overlapping data, the new topology was back casted at a monthly level from 1993 to 2002 for each LBA/LSE. This data, along with the data collected from sources other than EV, were summed to get hourly loads for each of the nine LRZs and MISO to the extent possible. MISO and LRZ monthly peaks were then derived from these hourly loads. Whera calculating at an hourly level was not possible, the data was summed at a monthly peak level.

MISO collected LBA-level load data to be consistent with 2013 MISO footprint and also included South LBAs that will join MISO footprint in December 2013, the list of LBAs is provided in Table A.1-3. This table along with Table A.1-4 provides acronyms for LBAs and the additional areas used in the power flow analysis.

No.	Local Balancing Area	Acronym	Zone
1	Dairyland Power Cooperative	DPC	LRZ-1
2	Great River Energy	GRE	LRZ-1
3	Minnesota Power	MP	LRZ-1
4	Montana-Dakota Utilities Co.	MDU	LRZ-1
5	Northern States Power Co. (Xcel)	NSP/XEL	LRZ-1
6	Otter Tail Power Co.	OTP	LRZ-1
7	Southern MN Municipal Power Agency	SMP	LRZ-1
8	Alliant East - Wisconsin Power and Light Co.	ALTE	LRZ-2
9	Madison Gas and Electric Co.	MGE	LRZ-2
10	Upper Peninsula Power Co.	UPPC	LRZ-2
11	Wisconsin Electric Power Co.	WEC	LRZ-2
12	Wisconsin Public Service Corp.	WPS	LRZ-2
13	Alliant West - Interstate Power & Light	ALTW	LRZ-3
14	MidAmerican Energy Co.	MEC	LRZ-3
15	Muscatine Power & Water	MPW	LRZ-3
16	Ameren Illinois	AMIL	LRZ-4
17	Southern Illinois Power Cooperative	SIPC	LRZ-4
18	Springfield Illinois - City Water Light & Power	CWLP	LRZ-4
19	Ameren Missouri	AMMO	LRZ-5
20	Columbia Missouri Water and Light Department	CWLD	LRZ-5
21	Big Rivers Electric Corp.	BREC	LRZ-6
22	Duke Energy Indiana	DUK(IN)	LRZ-6
23	Hoosier Energy Rural Elec.	HE	LRZ-6
24	Indianapolis Power & Light	IPL	LRZ-6
25	Northern Indiana Public Service	NIPSCO	LRZ-6
26	Southern Indiana Gas & Electric	SIGE	LRZ-6
27	Consumers Energy – METC	CONS	LRZ-7
28	Detroit Edison Company	DECO	LRZ-7
29	Entergy Arkansas	EAI	LRZ-8

30	Arkansas Electric Cooperative Corp.	*EAI	LRZ-8
31	Central Louisiana Electric Co. Inc.	CLECO	LRZ-9
32	Entergy Gulf States	EES	LRZ-9
33	Entergy Louisiana	EES	LRZ-9
34	Entergy Mississippi	EES	LRZ-9
35	Entergy New Orleans	EES	LRZ-9
36	Entergy Texas	EES	LRZ-9
37	Lafayette (City of)	LAFA	LRZ-9
38	Louisiana Energy and Power Authority	LEPA	LRZ-9
39	Louisiana Generating/Cajun Electric	LAGN	LRZ-9
40	South Mississippi Electric Power Association	SME	LRZ-9

* represented by EAI

Table A.1-3: List of Local Balancing Authorities (LBA)

No.	Additional Power Flow Areas	Acronym	Zone
1	Plum Point Energy Associates, LLC	PLUM	LRZ-8
2	City of Osceola, Arkansas	OMLP	LRZ-8
3	City of West Memphis, Arkansas	WMU	LRZ-8
4	City of Conway, Arkansas	CWAY	LRZ-8
5	City of Benton, Arkansas	BUBA	LRZ-8
6	Union Power Partners, L.P.	PUPP	LRZ-8
7	City of North Little Rock, Arkansas	NLR	LRZ-8

Table A.1-4: List of additional power flow areas

A.2 MISO LFU results

Using the methodology discussed in Section A.1 and the data set explained in Section A.1.1, the MISO LFU for the planning year 2014 is 3 percent. In addition to MISO-wide LFU, MISO also calculated LFU for its nine LRZs. MISO developed an auto-regression model for each LRZ and the LFU results are displayed in Table A.2-1. Tha definitions of the nine LRZs are indicated in Table A.1-3.

Zones	LFU
LRZ 1	2.9%
LRZ 2	4.5%
LRZ 3	3.0%
LRZ 4	4.7%
LRZ 5	4.4%
LRZ 6	3.5%
LRZ 7	5.3%
LRZ 8	5.0%
LRZ 9	3.2%

Table A.2-1: Zonal LFU results

Appendix B: Comparison of Planning Year 2013 to 2014

To compute changes in the Planning Reserve Margin (PRM) target on an Unforced Capacity (UCAP) and Installed Capacity (ICAP) basis, from the 2013-2014 planning year to the 2014-2015 planning year, multiple study sensitivity analyses were performed. These sensitivities included one-off incremental changes of input parameters to quantify how each change affected the PRM result independently. Since several enhancements were added as a part of the 2014-2015 study, it was first necessary to quantify how these enhancements would have impacted the 2013 PRM results in order to more accurately measure the incremental changes of input parameters had on the 2014 PRM results. Figure B-1 shows how the 2013 PRM_{UCAP} would have changed had the 2013 study been modeled exactly like the 2014 study. These enhancements are explained in section B.1. The impact of the incremental PRM changes from 2013 to 2014 are shown in the waterfall chart of Figure B-2 and explained in section B.1 as well. Before any LFU impacts are realized, the most significant increases in PRM_{UCAP} are due to Midwest internal and external changes (6.3% to 7.1%). Similarly, Figures B-3 and B-4 show the same changes expressed in ICAP.

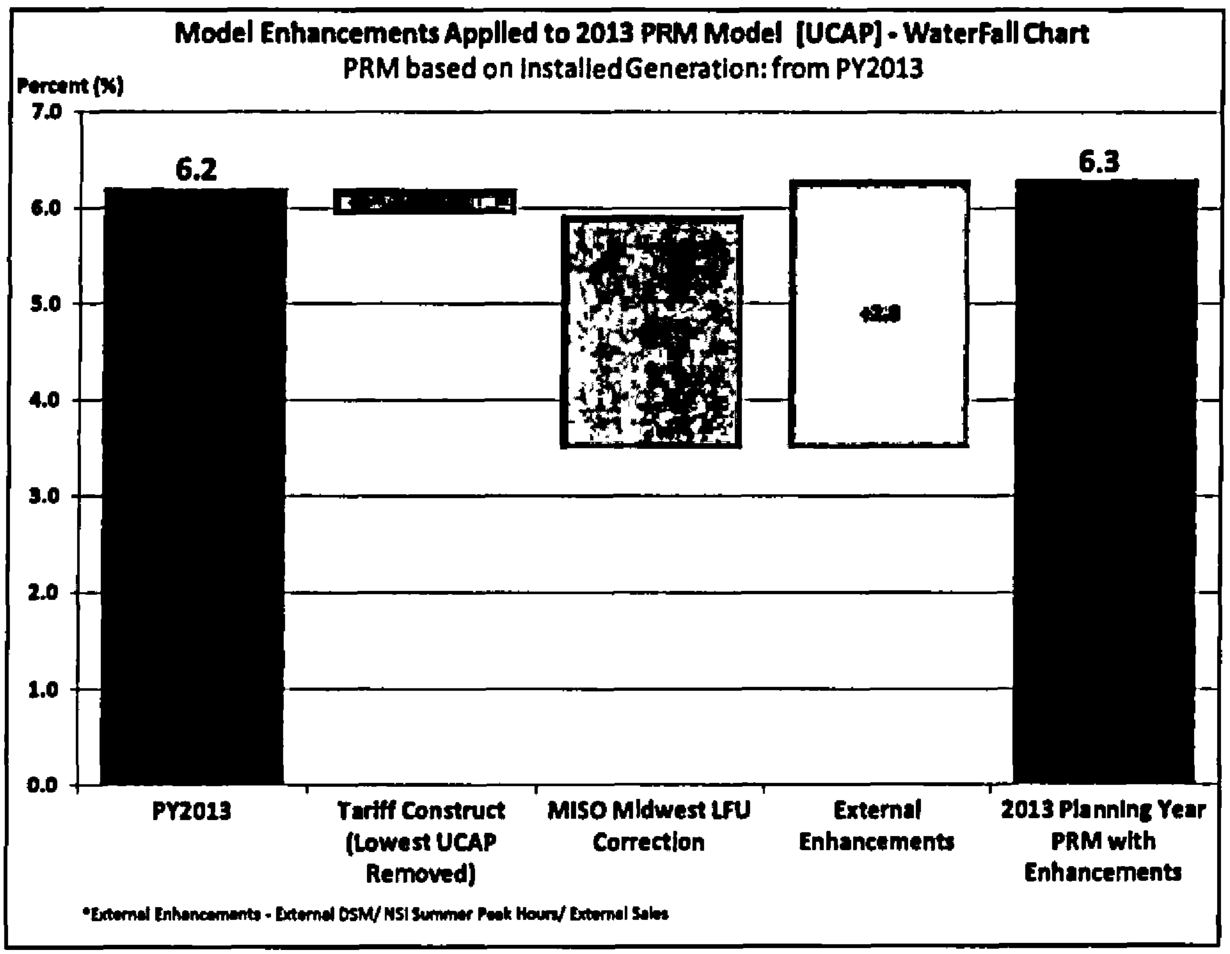


Figure B-1: Waterfall chart of 2013 PRM_{UCAP} with 2014 enhancements

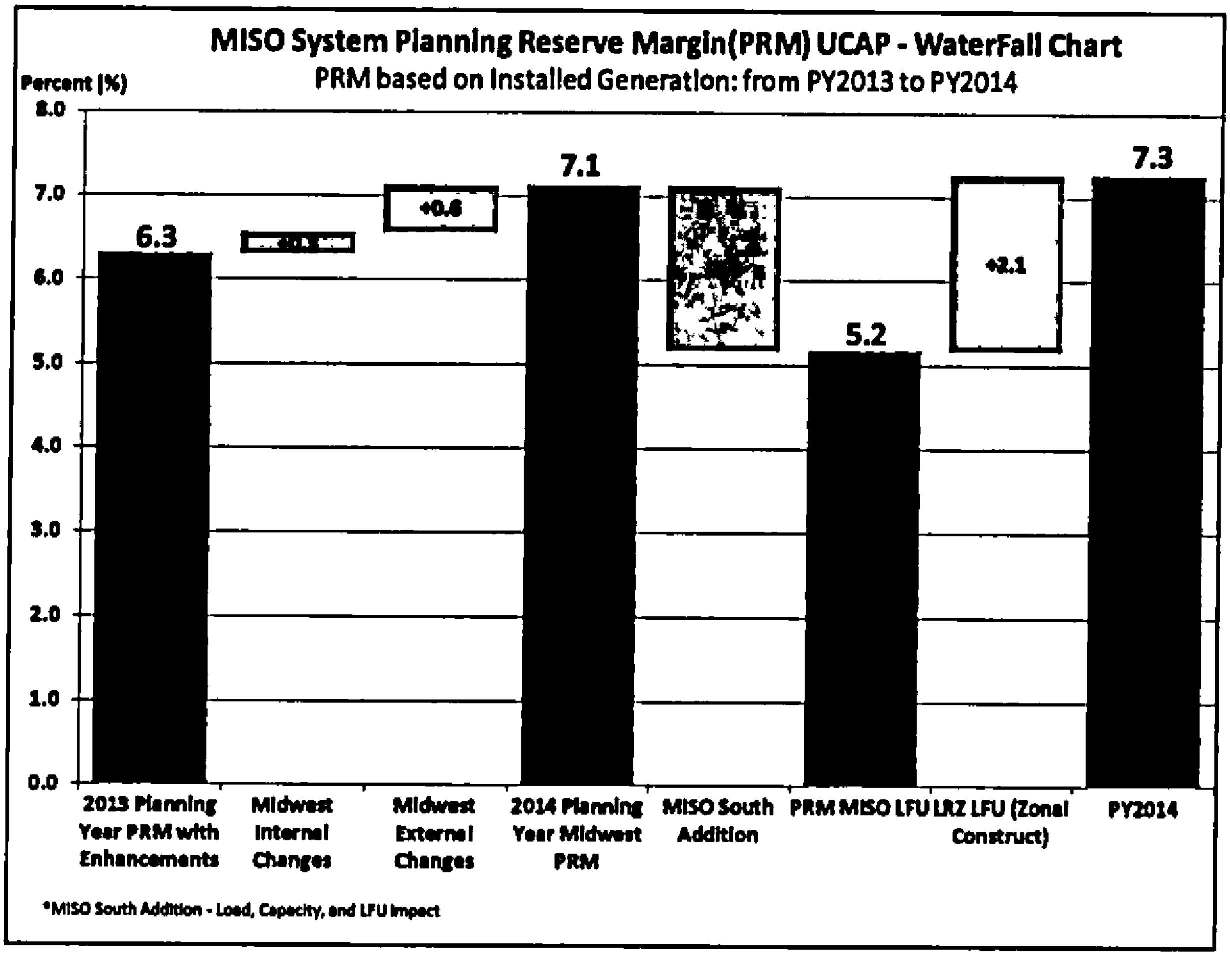


Figure B-2: Waterfall chart of PRM_{UCAP} changes, Planning Year 2013 to 2014

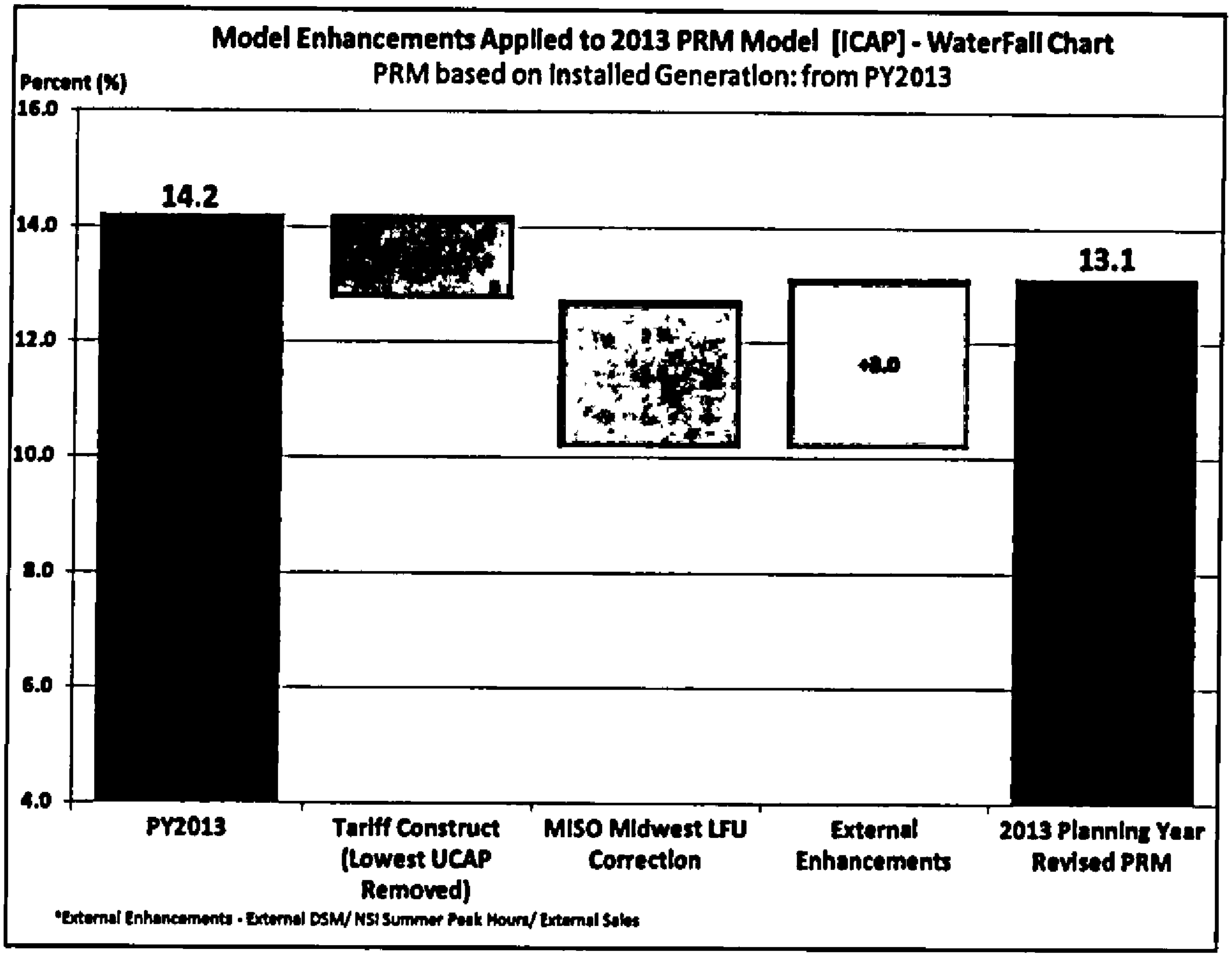


Figure B-3: Waterfall chart of 2013 PRM_{ICAP} with 2014 enhancements

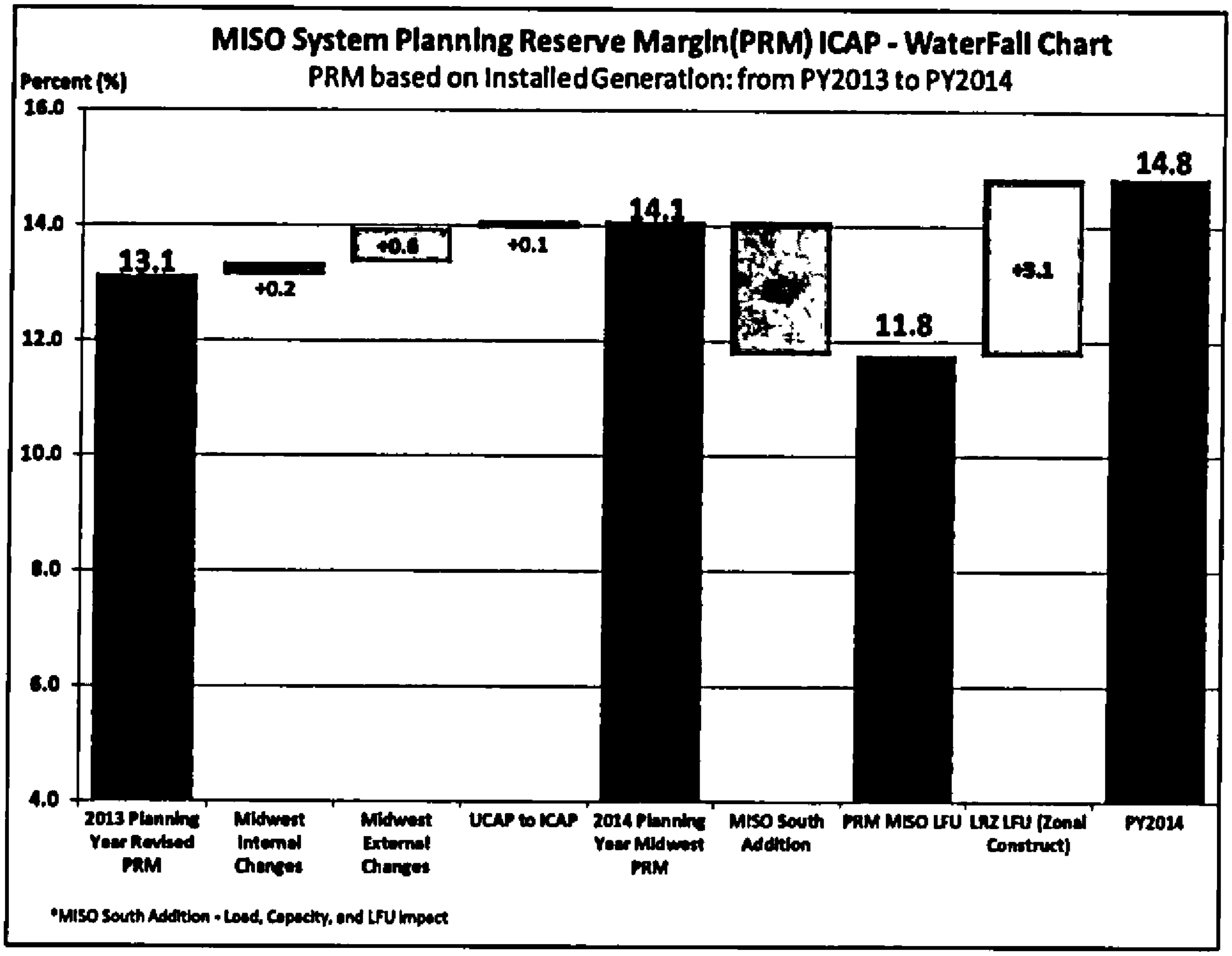


Figure B-4: Waterfall chart of PRM_{ICAP} changes, Planning Year 2013 to 2014

B.1. Waterfall Chart Details

B.1.1 Tariff Construct

A change was made in how capacity is adjusted in the LOLE model to reach a LOLE of 0.1 days per year. This change was made to align the adjustment methodology in the tariff with what was actually being done in the model. In previous years, capacity was adjusted by adding either a perfect negative or positive generator to reach a LOLE of 0.1 days per year. The 2014 PRM study adjusts capacity by removing the units with the smallest UCAP when an area or zone has excess capacity and needs capacity removed to meet 0.1 days per year. When an area or zone needs capacity to meet 0.1 days per year, units with an installed capacity of 160 MW are added with a class average forced outage rate until the reliability criteria is met.

B.1.2 MISO Midwest LFU Correction

Prior to the 2013 planning year, MISO utilized the NERC calculated uncertainty bandwidths. When the NERC load forecasting working group disbanded, MISO decided to apply the NERC bandwidth methodology to determine the Load Forecast Uncertainty (LFU) values for the 2013 planning year. There was an error in the 2013 LFU calculation because a bandwidth was used instead of a sigma uncertainty value. The error has been corrected and the NERC bandwidth methodology was applied appropriately for the 2014 planning year.

B.1.3 External Enhancements

The external system was modeled with several enhancements in the 2014-2015 planning year LOLE analysis. Prior to the 2014 study, external areas demand-side management (DSM) programs were relied upon to meet a MISO-wide PRM value. The 2014 study removed the reliance on the external DSM programs by determining the MISO PRM values without relying on external regions to call their DSM.

Another enhancement in the external system modeling was the net scheduled interchange values were limited to the previous year's summer peak hours only. In previous studies, the NSI values were determined by the maximum NSI value over the entire previous year rather than the summer peak hours only. This change was made to more accurately reflect available external support in a MISO peak demand scenario when a loss of load event is most likely to occur.

The last change to the external system was that external sales were modeled. MISO units that were designated in PJM's market were derated or removed from the PRM study model.

B.1.4 Midwest Internal Changes

The Midwest internal changes include internal capacity and load changes (retirements, suspensions, updated GADS data and load forecast changes).

B.1.5 Midwest External Changes

The Midwest external changes include decreased assistance from external regions when compared to last year's support (external regions tie limits reduced and firm external purchases decreased).

B.1.6 UCAP to ICAP (ICAP Waterfall Chart Only)

In previous PRM studies, the UCAP was assumed to equal ICAP when adjusting capacity with a perfect unit. By moving to the adjustment methodology to align with the tariff, ICAP is no longer equal to UCAP and the ICAP value associated with the UCAP needed to meet 0.1 days per year LOLE is greater, which is used in the PRM_{ICAP} calculation.

B.1.7 MISO South Addition

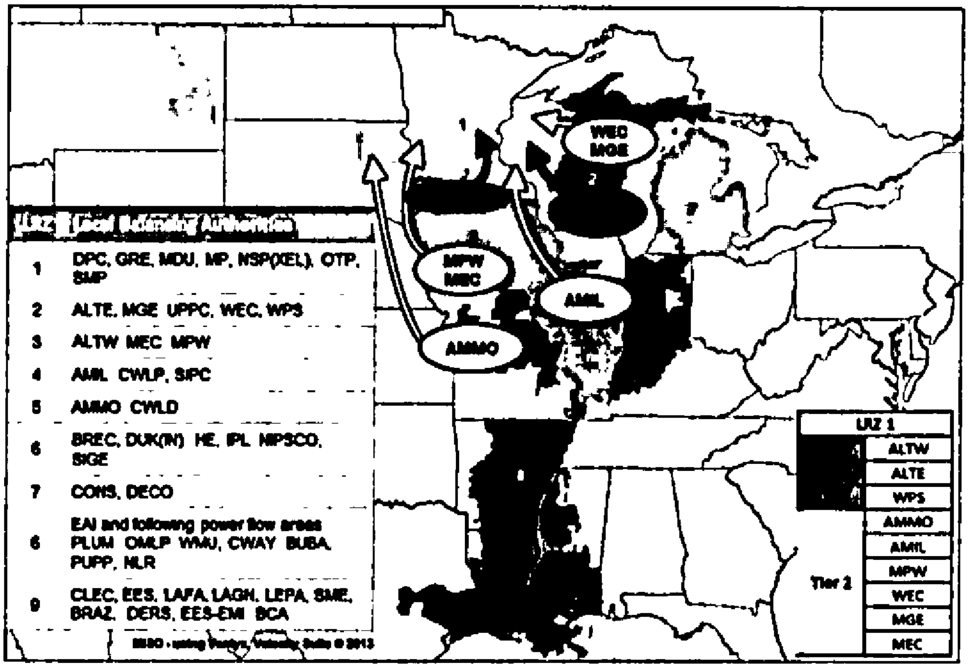
Since MISO South will integrete in December 2013 it was included in the 2014-2015 PRM study. These companies increased the load diversity with the MISO system and lowered MISO's overell LFU.

B.1.8 LRZ LFU (Zonal Construct)

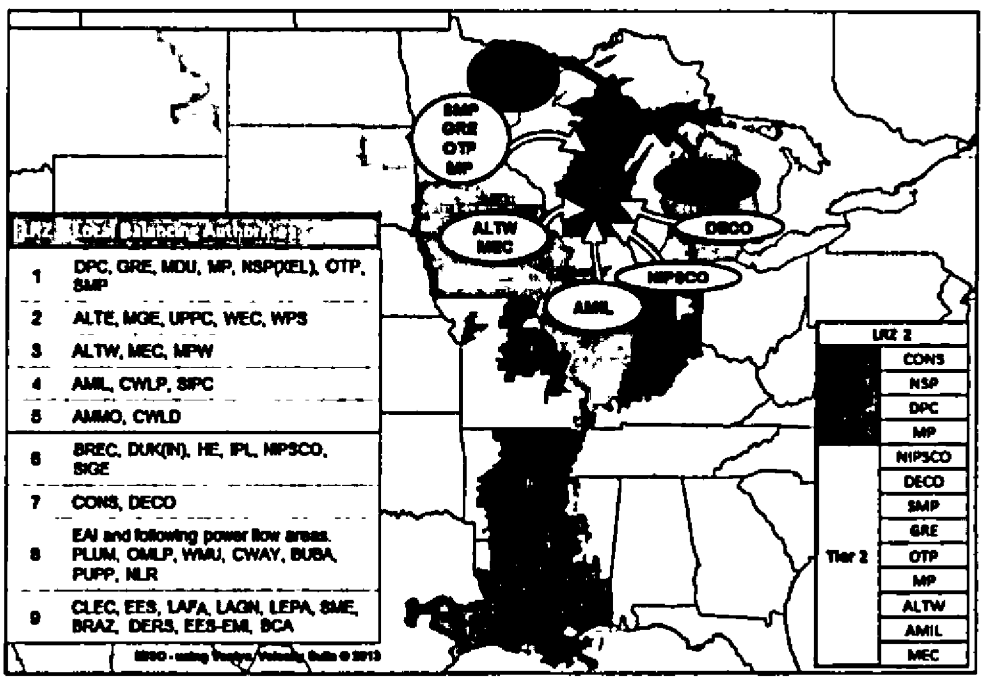
The 2014 PRM study models each of the nine individual LRZ's as part of a larger MISO pool. By modeling all nine LRZs, their LRZ specific LFU is appropriately applied to their LRZ load instead of aggregating into one MISO region and creating one MISO-wide LFU. Previous years modeled one MISO-wide LFU, but the new approach aligns the MISO PRM analysis with the zonal construct and LRZ LOLE analysis. The PRM increases because the individual zones have higher LFU values than the combined MISO LFU (more grenular representation of uncertainty).

Appendix C: Transfer Analysis

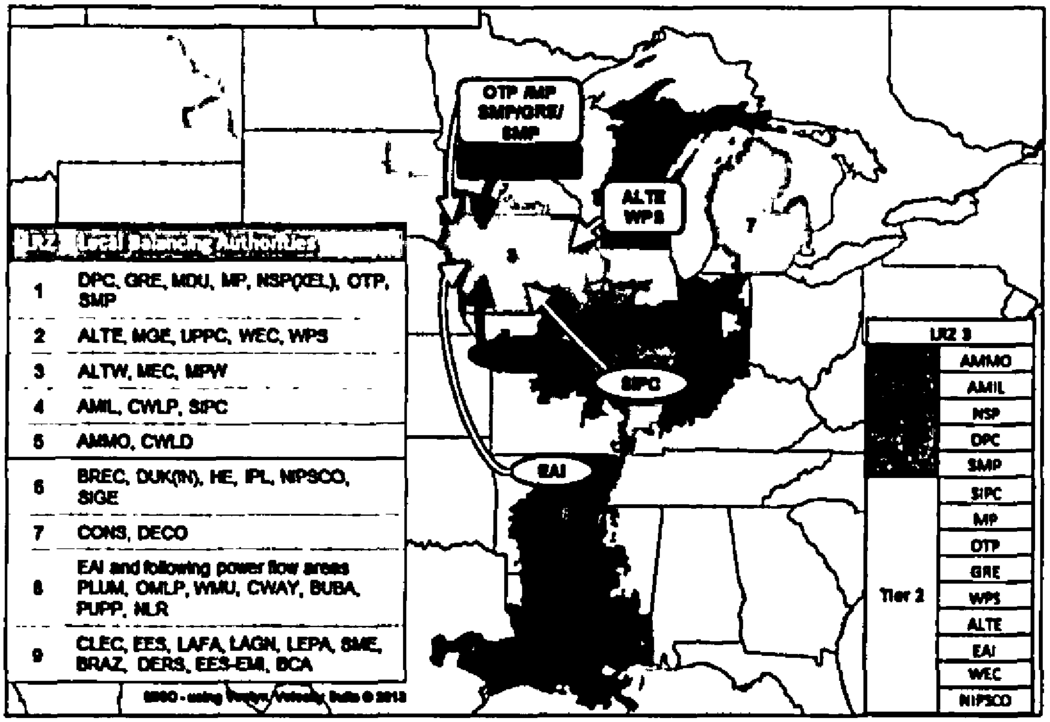
C.1: Tier Maps



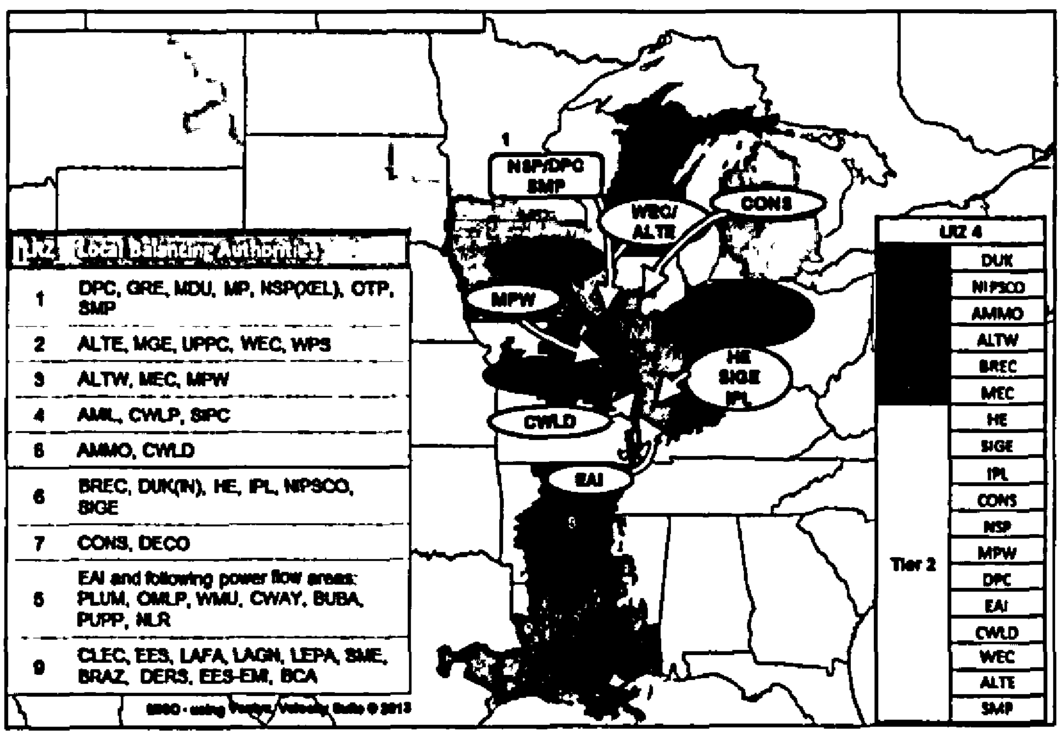
Zone 1: DPC, GRE, MDU, MP, OTP, SMMPA, XEL



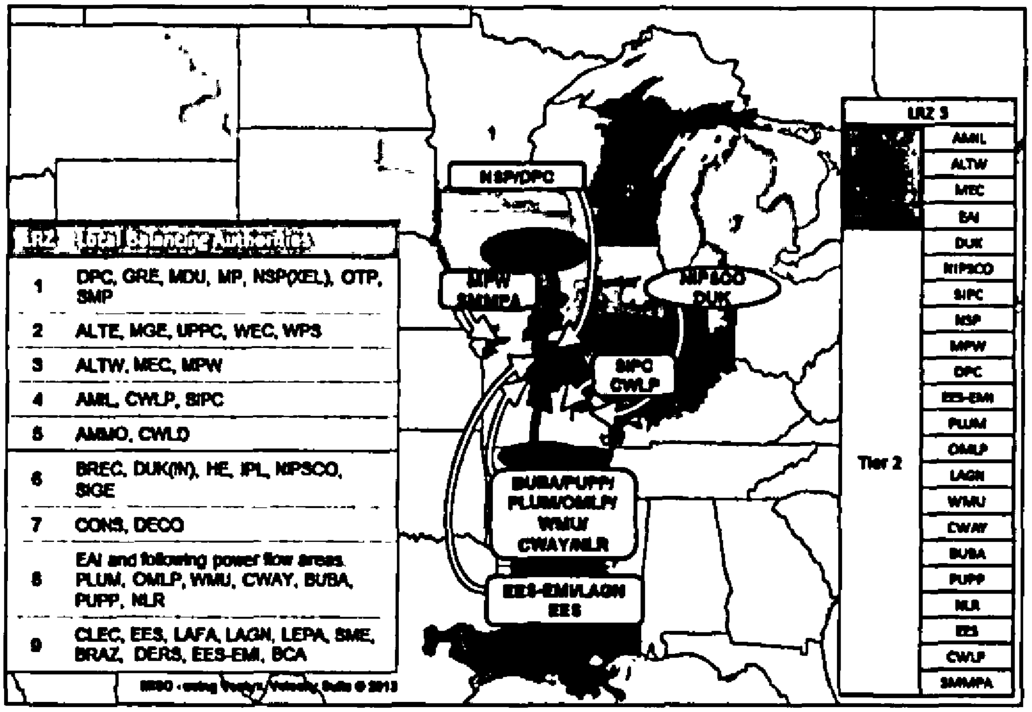
Zone 2: ALTE, MGE, UPPC, WEC, WPS



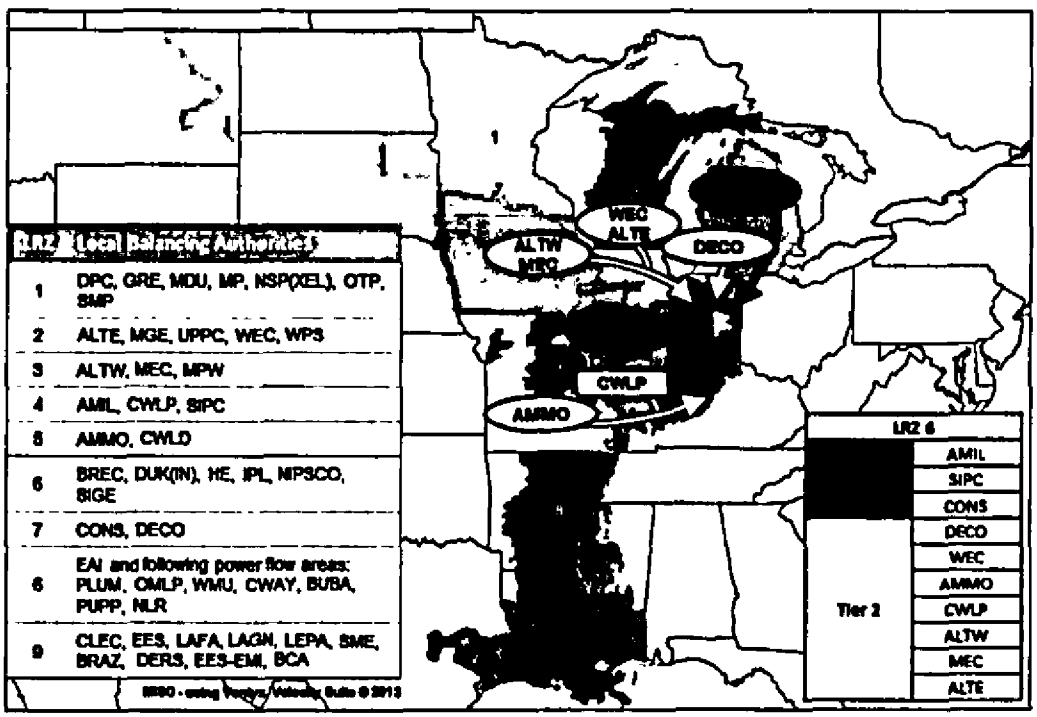
Zone 3: ALTW, MEC, MPW



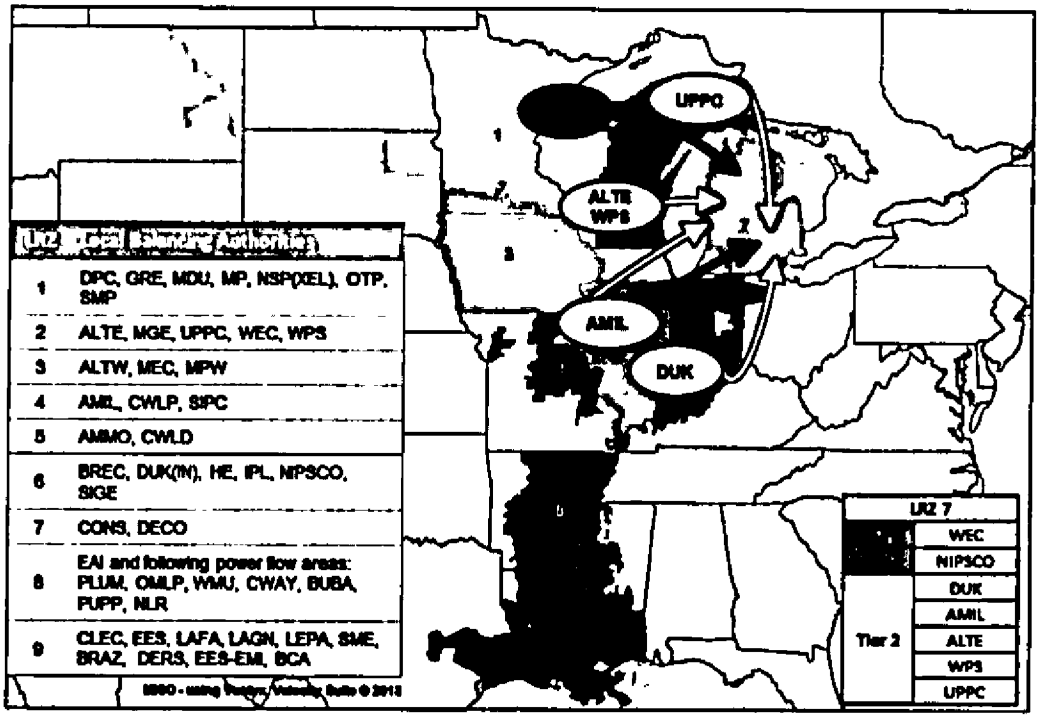
Zone 4: AMIL, CWLP, SIPC



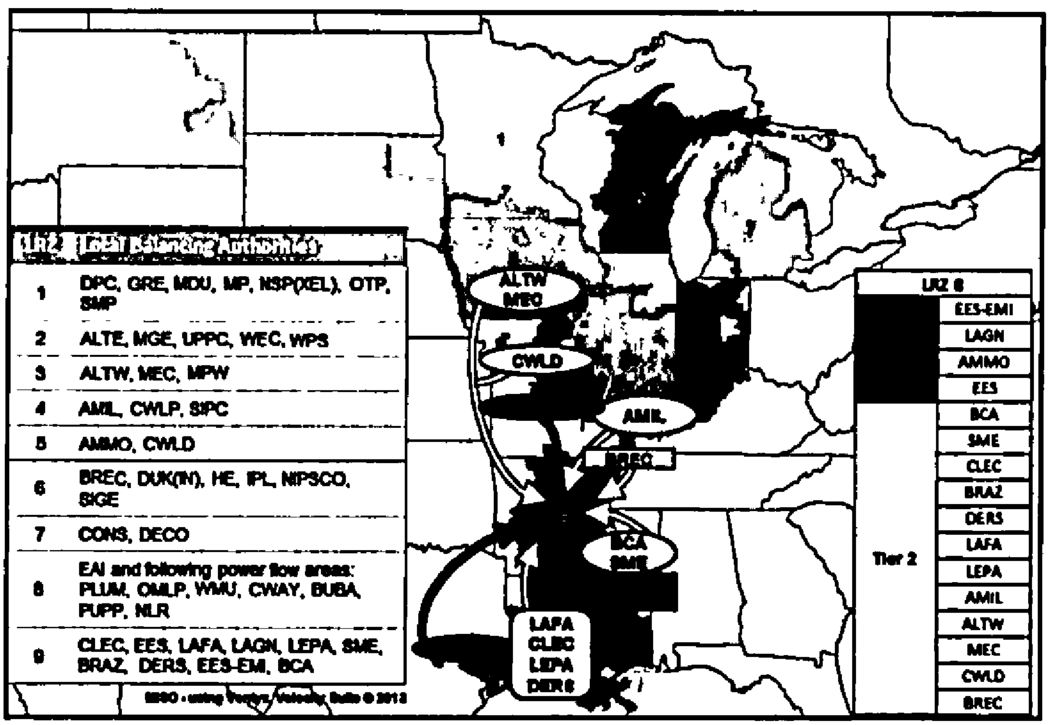
Zone 5: AMMO, CWLD



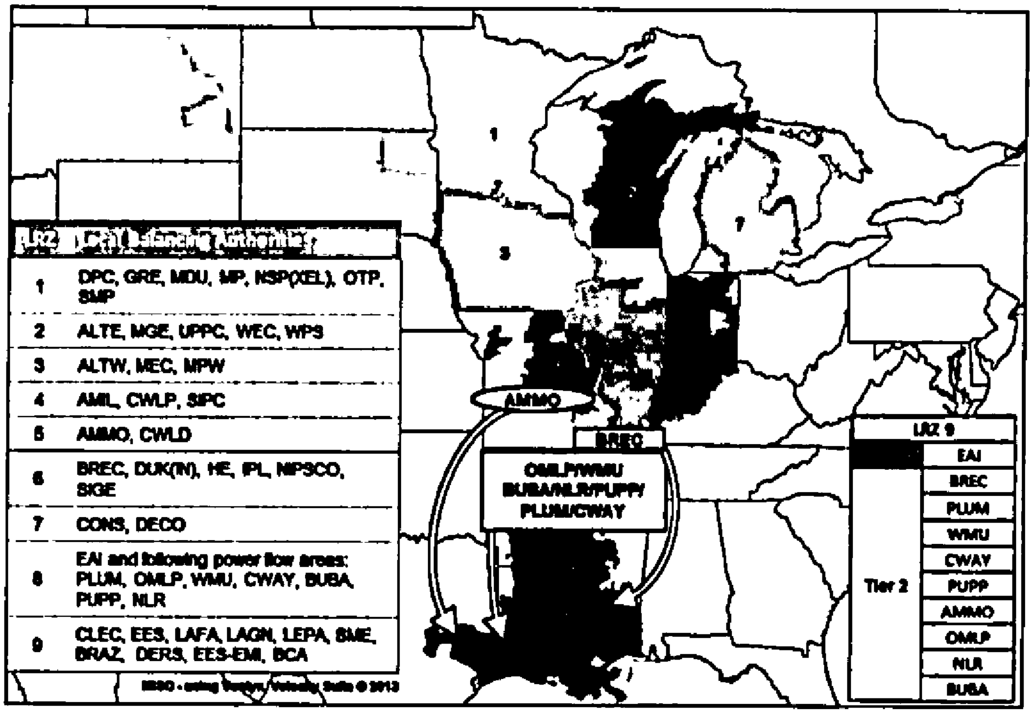
Zone 6: BREC, DEM, HE, IPL, NIPS, SIGE



Zone 7: ITC, MECS



Zone 8: EAI (PLUM, OMLP, WMU, CWAY, BUBA, PUPP, NLR)



Zone 9: CLEC, EES, LAFA, LEPA, SME, BRAZ, LAGN, DERS, EES-EMI, BCA

C.2: 2014 Detailed Results

Zone 1 CIL

- Initial limit 4,292 MW
  - Constraint: Lime Creek to Worth County 161 kV line (Figure C.2-1)
    - Contingency: Barton to Adams 161 kV line
  - Redispatch was tested and mitigated the constraint completely: 68 MW of generation, 9 generators in ALTW, WPS, and ALTE
  - A more limiting constraint was presented at the September 4, 2013, LOLEWG meeting due to an invalid contingency

- Current limit 4,347 MW
  - Limit is based on available capacity in Tier 1 after redispatch plus base import.

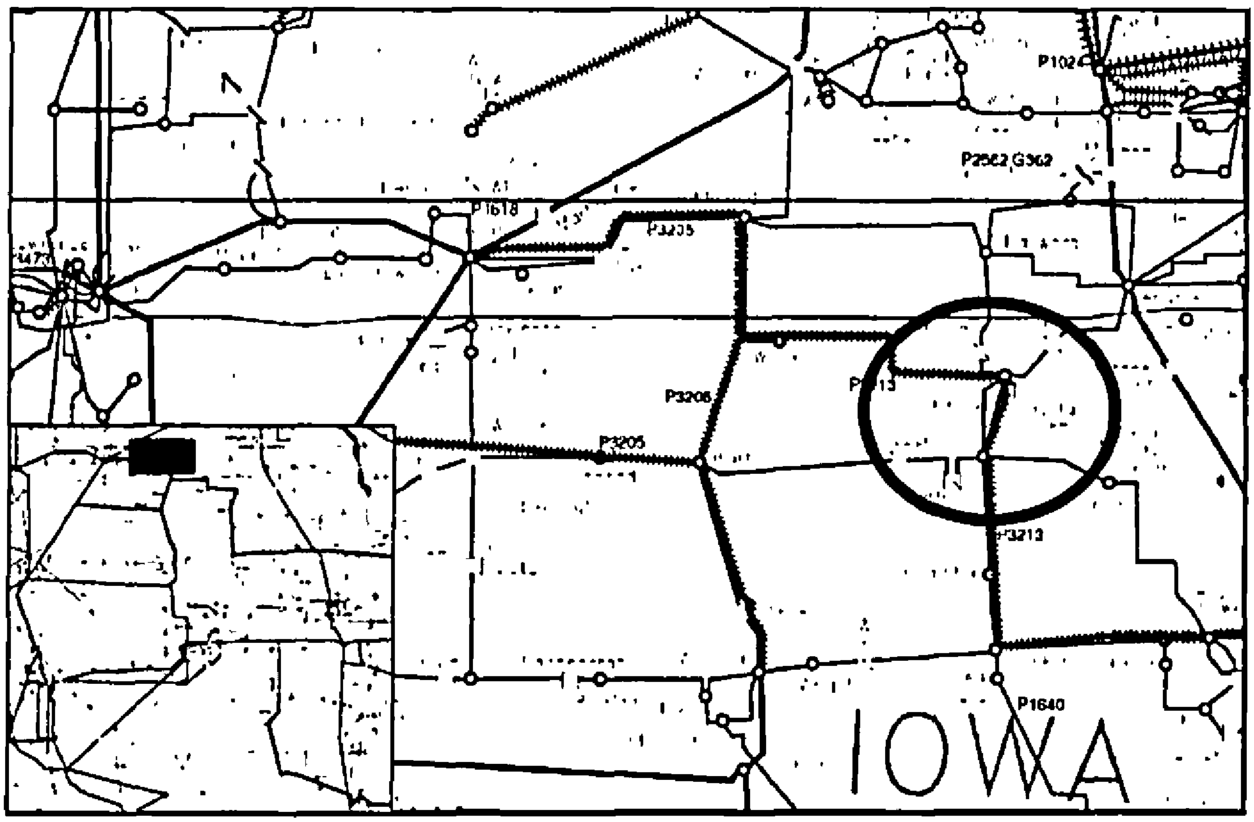


Figure C.2-1: Zone 1 Import Constraint

Zone 1 CEL

- Initial limit 48 MW
  - Constraint: Lakefield to Dickinson 161 kV line (Figure C.2-2)
    - Contingency: Webster 345 kV substation
  - Redispatch applied: 515 MW of generation, 10 generators in GRE, NSP, and DPC

- Current limit 286 MW
  - Export is limited by the amount of generation in Zone 1

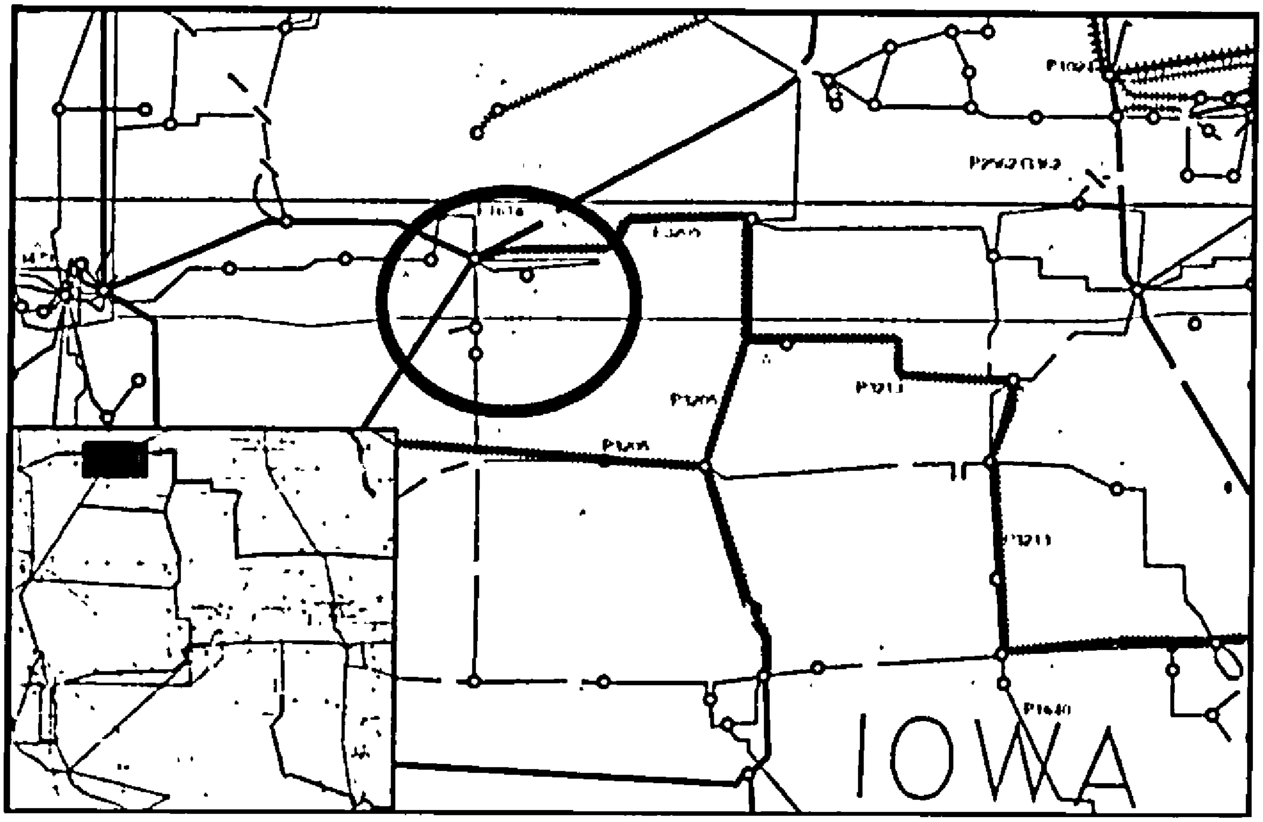
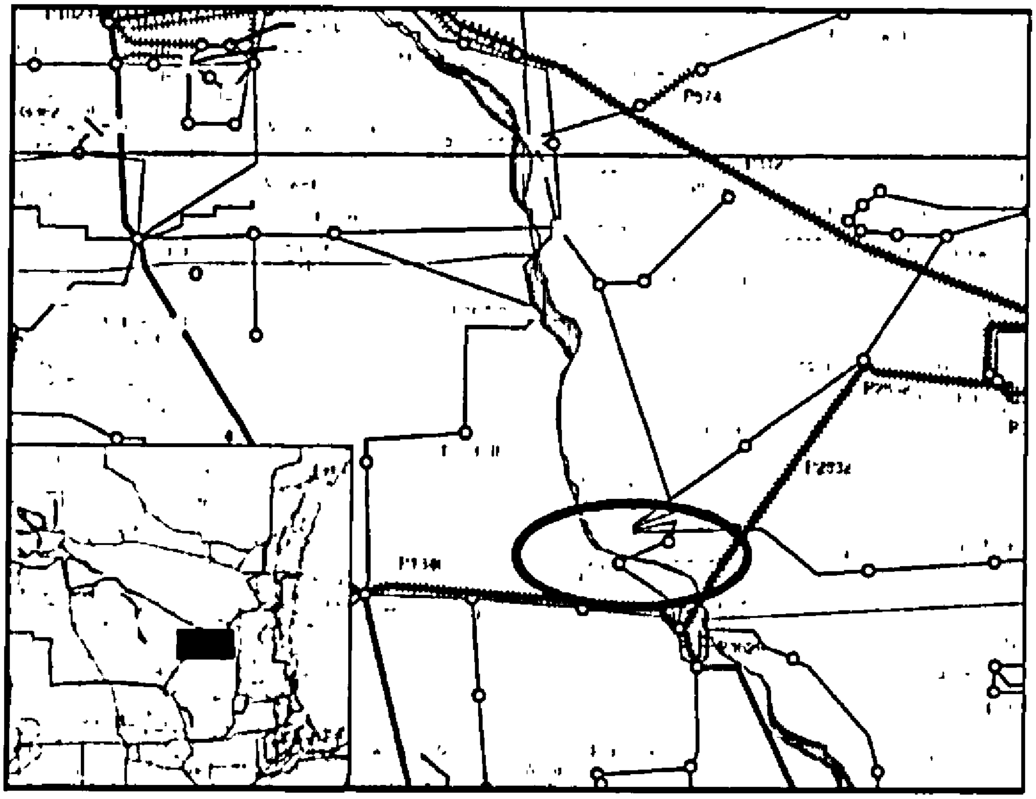


Figure C.2-2: Zone 1 Export Constraint

Zone 2 CIL

- Initial limit 2,859 MW
    - Constraint: Turkey River to Stoneman 161 kV line (Figure C.2-3)
        - Contingency: Genoa to Seneca 161 kV line
    - Initially redispatch was applied and focused on only redispatching generation within Tier 1: 166 MW, 10 generators in XEL and DPC. This allowed the limit to increase to 2,946 MW for the same constraint above. After stakeholder discussion MISO agreed that all MISO units should be considered in ramping down generation and Tier 1 generation will be considered to ramp up.

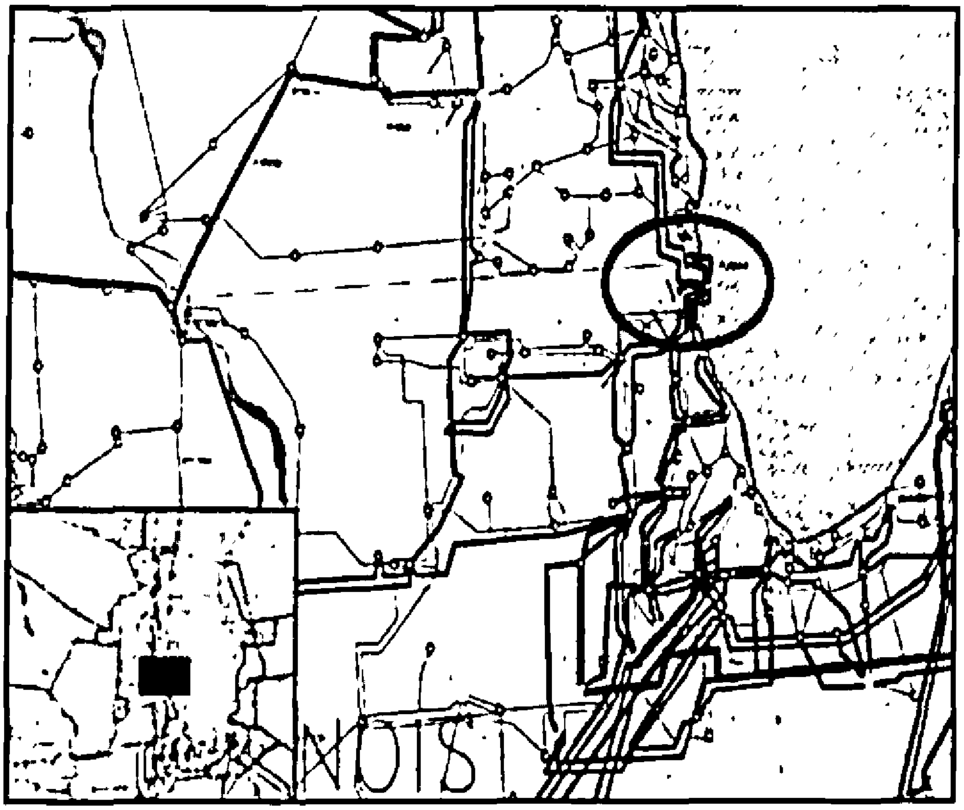
- Current limit 3,083 MW for the same constraint identified above.
    - The redispatch scenario that allows the 3,083 MW limit is: 162 MW of generation, 10 generators in ALTW, XEL and DPC. The non-Tier 1 area considered is ALTW.



Map C.2-3: Zone 2 Import Constraint

<u>Zone 2 CEL</u>

- Initial, pre-redispatch limit is 1,371
    - Constraint: Zion Station to Zion Energy Center 345 kV line (Figure C.2-4)
        - Contingency: Pleasant Prairie to Zion 345 kV line
    - Redispatch applied: 318 MW of generation, 10 generators in NIPS, WEC, and AMIL
        - Zone 2 export limited by same constraint identified for Zone 7 import limit, same redispatch scenario was applied
    - Zone 2 Capacity Export Limit required additional coordination with PJM to ensure MISO accurately accounted for a ComEd phase shifter in the analysis. Enhancing the study tool solution settings to accommodate the phase shifter eliminated several constraints.
- Current, post-redispatch Limit is 1,924 MW



Map C.2-4: Zone 2 Export Constraint

Zone 3 CIL

- Initial limit 0 MW
    - o Constraint: Palmyra 345/161 kV transformer (Figure C.2-5)
        - Contingency: Hills to Sub T to Louisa 345 kV line
    - o Redispatch applied: 211 MW of generation, 10 generators in AMMO and AMIL
- Next limit identified is 1,326 MW
    - o Constraint: Blackhawk to Hazleton 161 kV line
        - Contingency: Washburn to Hazleton 161 kV line
    - o Redispatch applied: 289 MW of generation, 7 generators in AMMO, XEL, and DPC
- Limit prior to updated redispatch methodology is 1,514 MW
    - o Constraint: Blackhawk to Hazleton 161 kV line
        - Contingency: Washburn to Hazleton 161 kV line
    - o Redispatch was re-evaluated to account for non-Tier 1 generation and optimized between the Palmyra and Blackhawk-Hazleton constraints.
        - Redispatch applied: 366 MW of generation, 10 generators in AMMO, GRE, and ALTE. GRE and ALTE are not part of Tier 1

- Current limit is 1,591 MW
    - o Constraint: Blackhawk to Hazleton 161 kV line (Figure C.2-6)
        - Contingency: Washburn to Hazleton 161 kV line

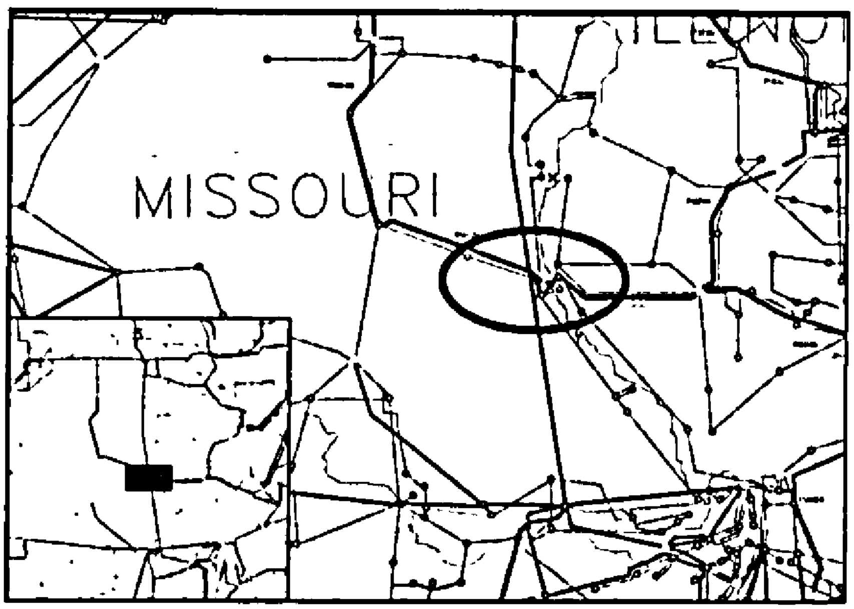


Figure C.2-5: Zone 3 Initial Import Constraint

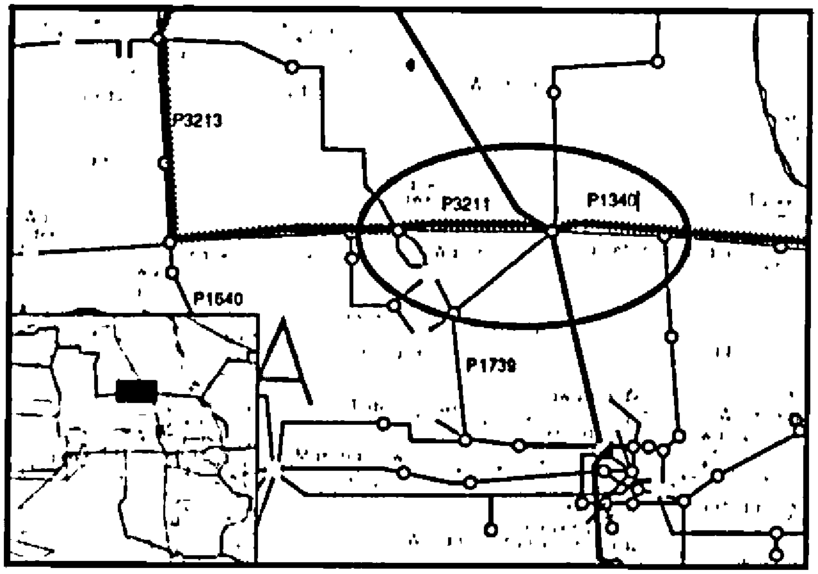
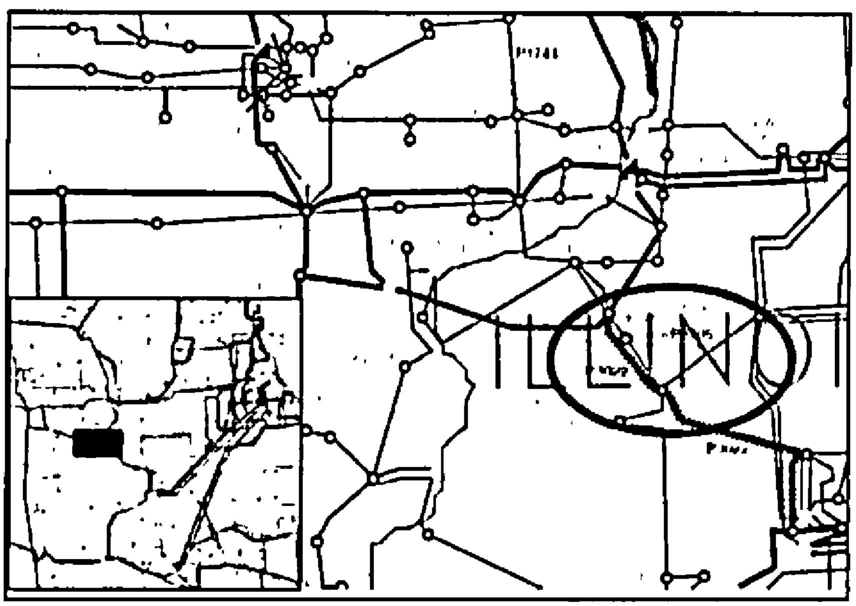


Figure C.2-6: Zone 3 Post-Redispatch Import Constraint

Zone 3 CEL

- Initial limit 1,875 MW
  - Constraint: Oak Grove to Galesburg 161 kV line (Figure C.2-7)
    - Contingency: Nelson to Electric Junction 345 kV line
  - Redispatch was tested and resulted in a more severe limiter
    - 458 MW of generation, 10 generators in MEC, MPW, and ALTW
- Current limit 1,875 MW



Map C.2-7: Zone 3 Export Constraint

Zone 4 CIL

- Initial limit 3,025 MW
    - o Constraint: Tazewell 345/138 kV transformer (#1) (Figure C.2-8)
        - Contingency: Tazewell 345/138 kV transformer (#2)
    - o Multiple redispatch scenarios were tested and resulted in a more severe limiter
        - 315 MW, 10 generators in MEC, ALTW, and NIPS
        - 303 MW, 10 generators in ComEd, MEC, ALTW, and NIPS

- Current limit 3,025 MW

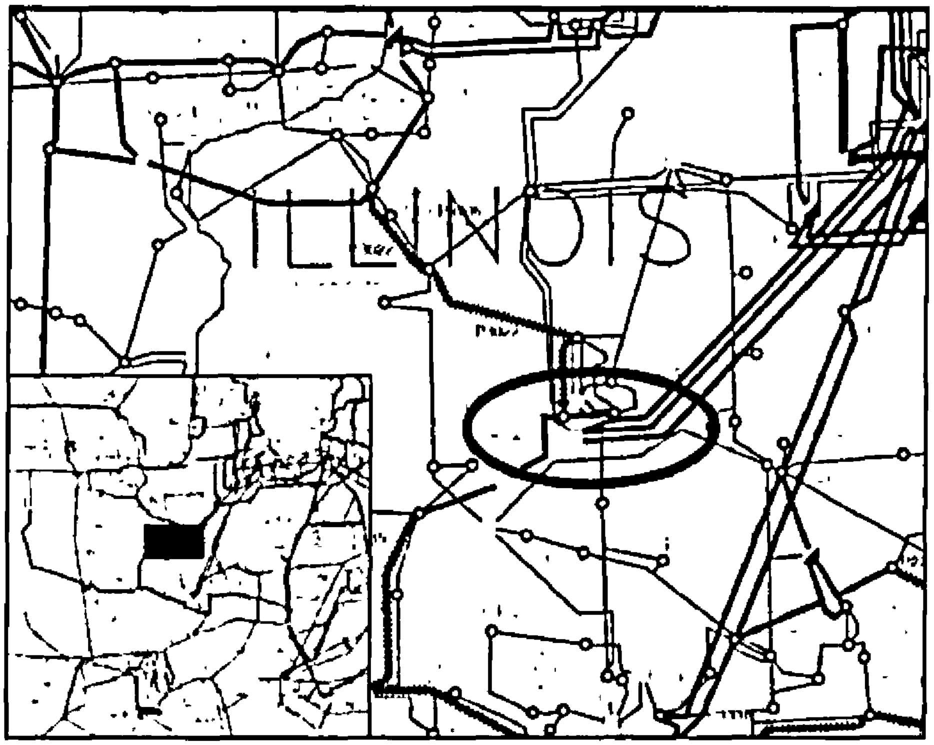


Figure C.2-8: Zone 4 Import Constraint

<u>Zone 4 CEL</u>

- Initial limit 1,961 MW
    - o Constraint: Pontiac to Loretto 345 kV line (Figure C.2-9)
        - Contingency:
          345-L8014_T_-S
          Close 272260 PONTIAC; B 138 272261 PONTIAC; R 138Z1
          Open 270717 DRESDEN; R 345 270853 PONTIAC; R 345 1
          Open 270853 PONTIAC; R 345 275210 PONTIAC; 2M 138 1
          Open 272261 PONTIAC; R 138 275210 PONTIAC; 2M 138 1
          Open 275210 PONTIAC; 2M 138 275310 PONTIAC; 2C34.5 1
    - o Redispatch was tested and resulted in a more severe limiter
        - 493 MW of generation, 10 generators in AMIL, CWLP, and SIPC
- Current limit 1,961 MW

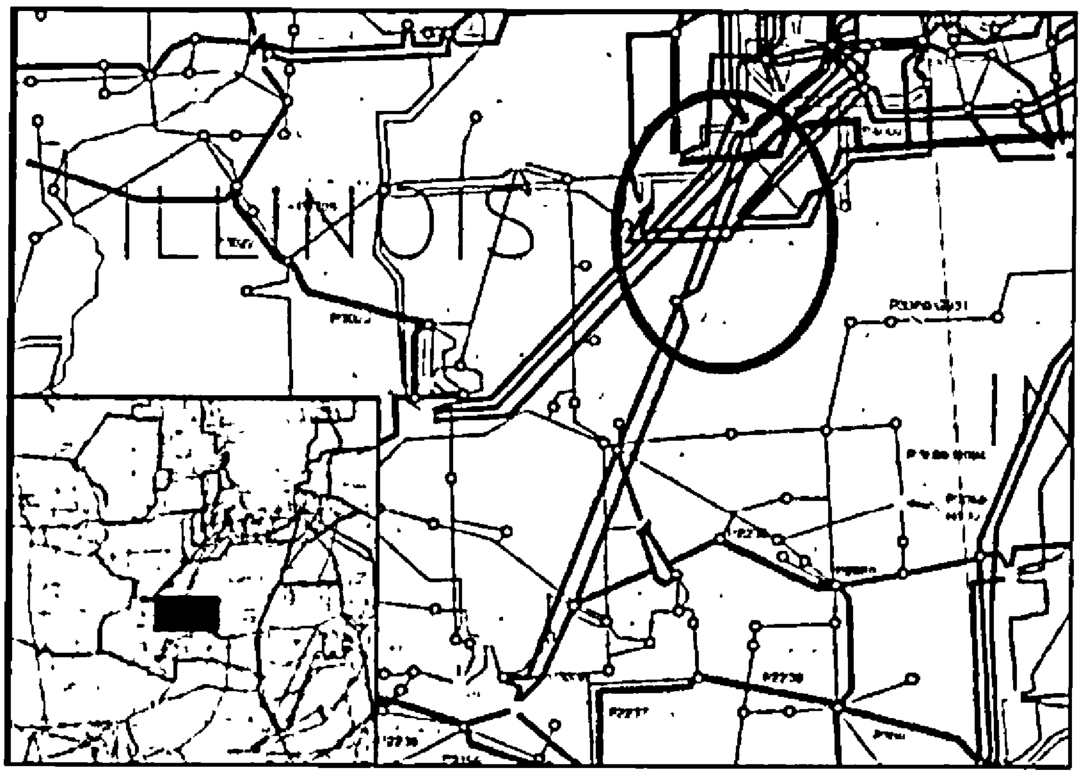


Figure C.2-9: Zone 4 Export Constraint

<u>Zone 5 CIL</u>

- Initial limit 4,712 MW
    - o Constraint: Hot Springs EHV to Arklahoma 115 kV line (Figure C.2-10)
        - ▪ Contingency: Carpenter to Arklahoma 115 kV line
    - o Redispatch applied: 539 MW of generation, 9 generators in EAI

- Current limit 5,273 MW
    - o Limit is based on available capacity in Tier 1 after redispatch plus base import.

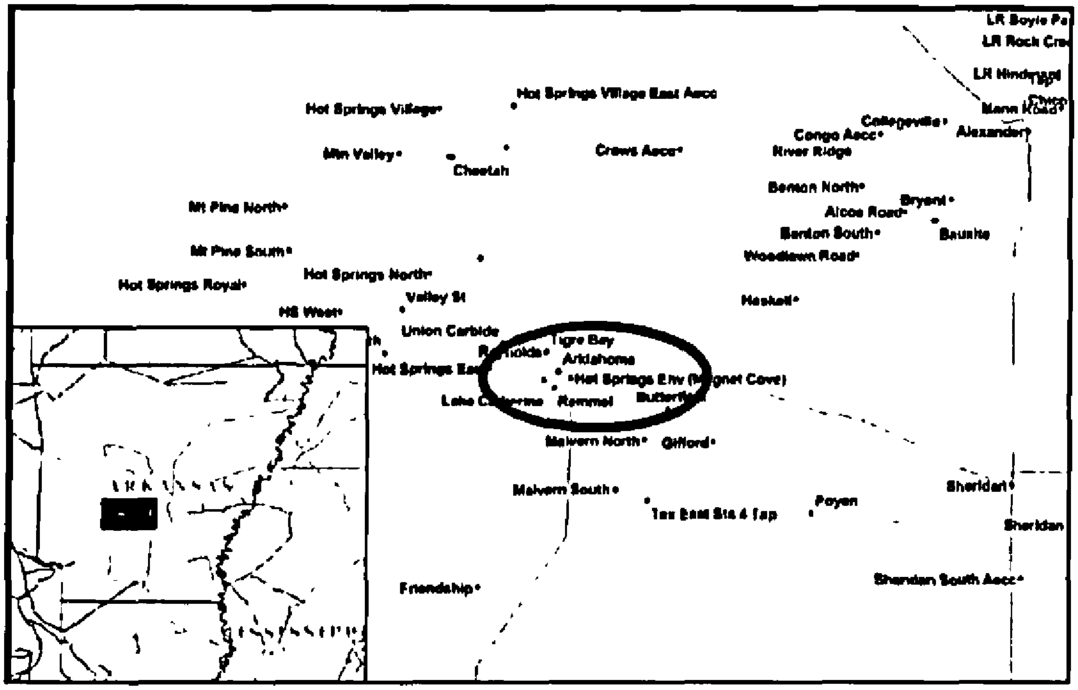


Figure C.2-10: Zone 5 Import Constraint

Zone 5 CEL

- Initial limit 793 MW
  - Constraint: Palmyra 345/161 kV transformer (Figure C.2-11)
    - Contingency: Hills to Sub T to Louisa 345 kV line
  - Redispatch applied: 238 MW of generation, 10 generators in AMMO and CWLD

- Current limit 1,350 MW for the same constraint identified above.

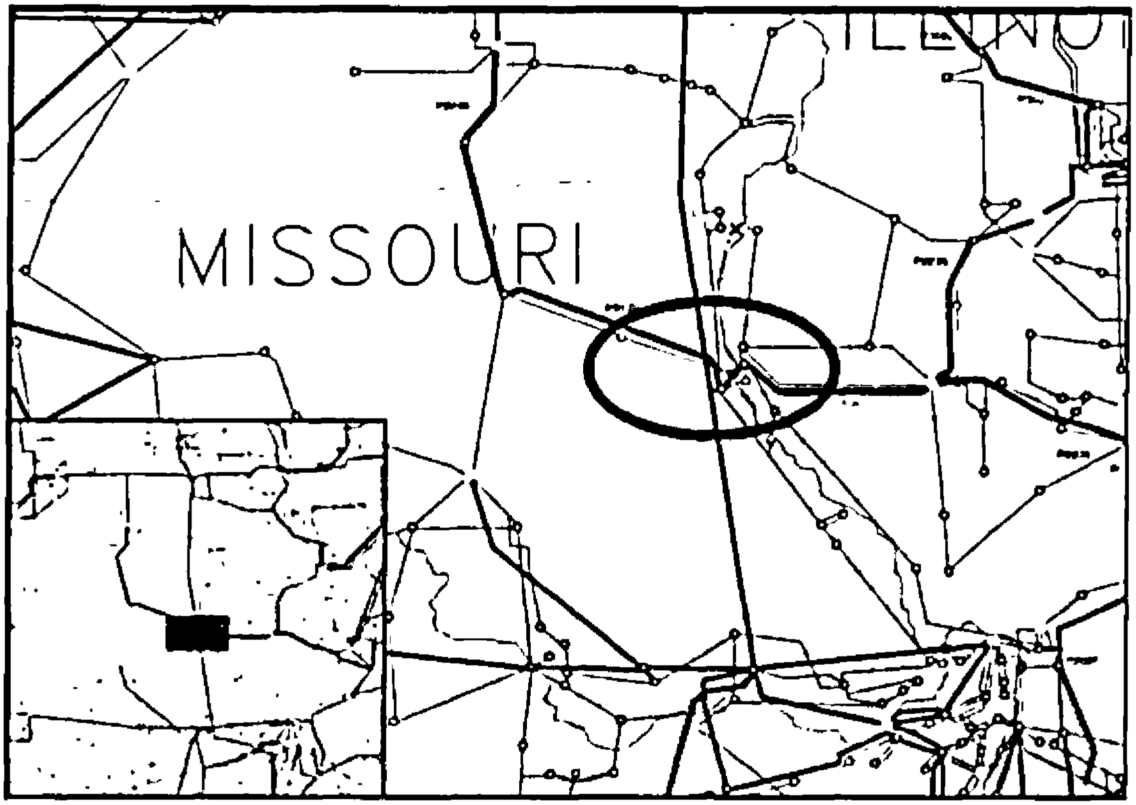
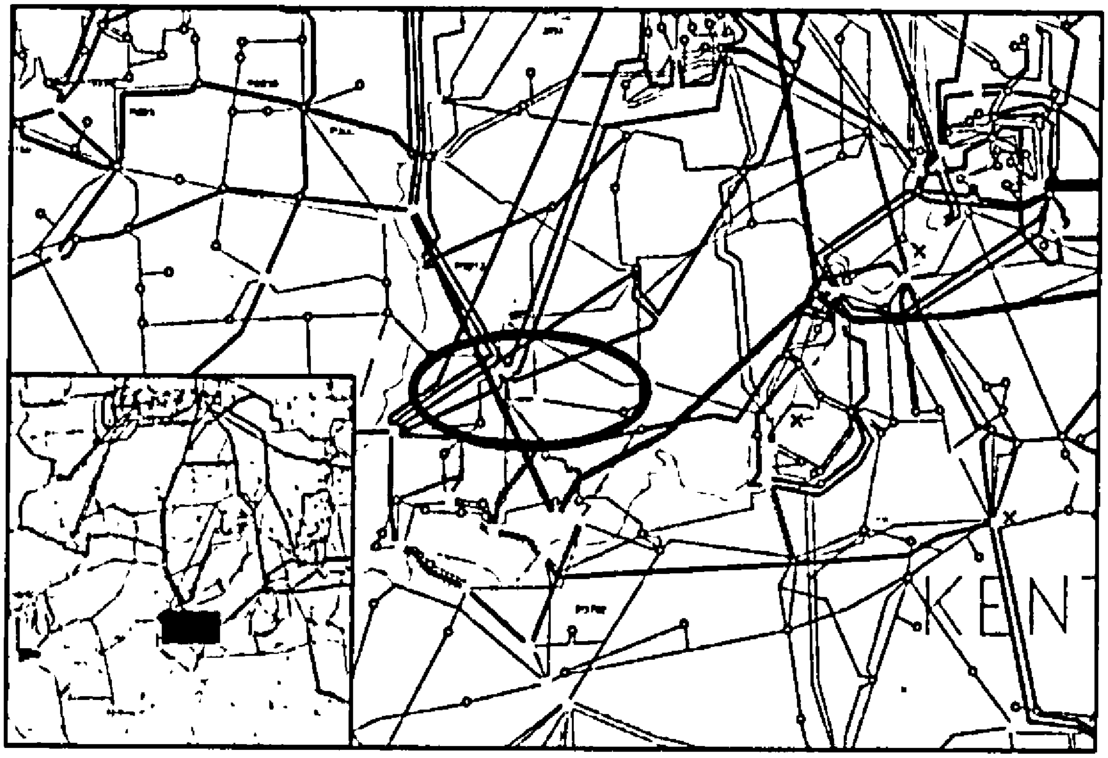


Figure C.2-11: Zone 5 Export Constraint

Zone 6 CIL

- Initial limit 4,834 MW
    - o Constraint: Wheatland to Petersburg 345 kV line (Figure C.2-12)
        - ▪ Contingency: Jefferson to Rockport 765 kV line
    - o Redispatch scenario tested and resulted in a more severe limiter
        - ▪ Redispatch applied: 633 MW of generation, 2 generators in METC and AMIL

- Current limit 4,834 MW



Map C.2-12: Zone 6 Import Constraint

Zone 6 CEL

- Limit is 2,246 MW
    - Limit reflects available capacity in the zone and base interchange
- A sensitivity analysis was completed to identify what the expected Transmission Limit for Zone 6 export may be. Load and generation in the zone were adjusted to increase amount of generation exported from the zone, which results in the following limiter:
    - Amo to Edwardsport 345 kV for loss of Gibson to Wheatland 345 kV.

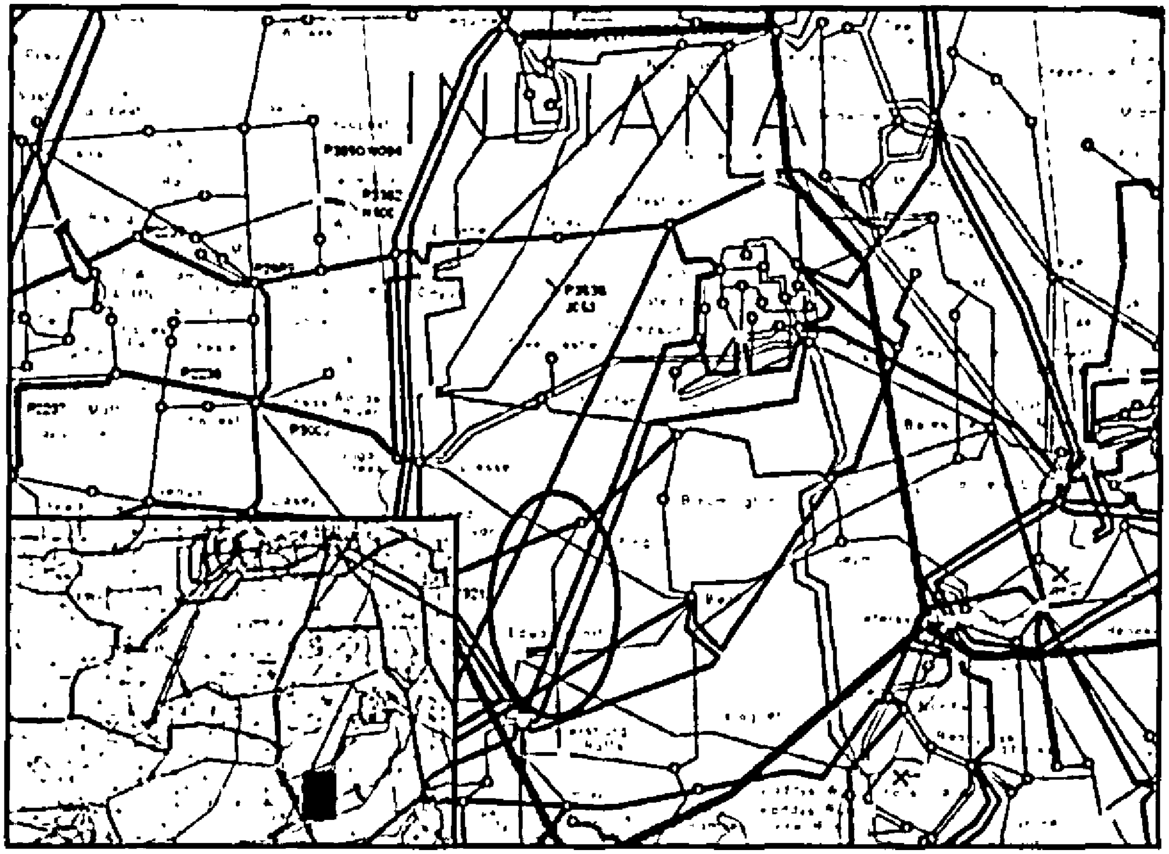


Figure C.2-13: Zone 6 Export Constraint

<u>Zone 7 CIL</u>

- Initial limit 2,587 MW
  - o Transfer using Tier 1 available capacity produced no constraints, so Tier 2 was added
  - o Constraint: Zion Station to Zion Energy Center 345 kV line (Figure C.2-14)
    - Contingency: Pleasant Prairie to Zion 345 kV line
  - o Redispatch applied: 318 MW of generation, 10 generetors in NIPS, WEC, and AMIL
    - Original redispatch tested and presented in early September are invalid due to a swing bus was included in the redispatch.

- Current limit 3,884 MW for the same constraint identified above.

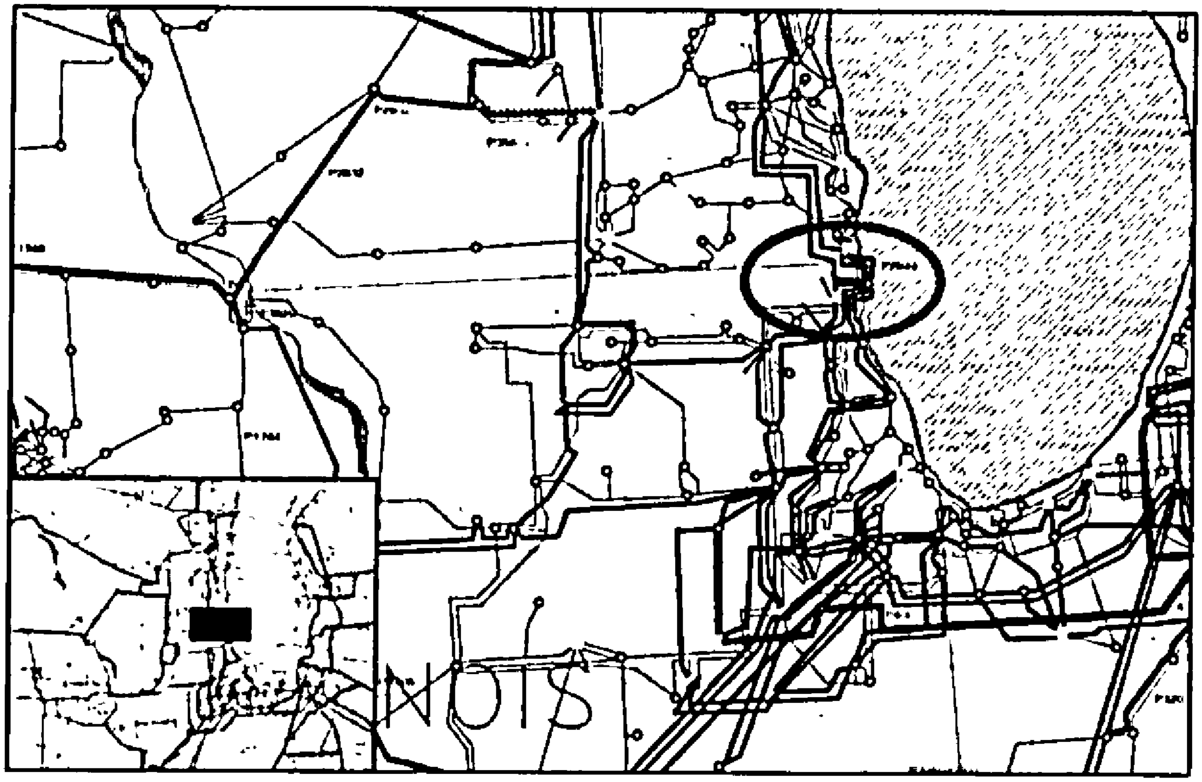


Figure C.2-14: Zone 7 Import Constraint

<u>Zone 7 CEL</u>

- Initial limit 4,517 MW
    - Constraint: Benton Harbor 345/138 kV transformer (Figure C.2-15)
        - Contingency: Benton Harbor to Cook 345 kV line
    - Redispatch was tested and resulted in a more severe limiter
        - 100 MW of generation, 2 generators in METC and ITCT

- Current limit 4,517 MW

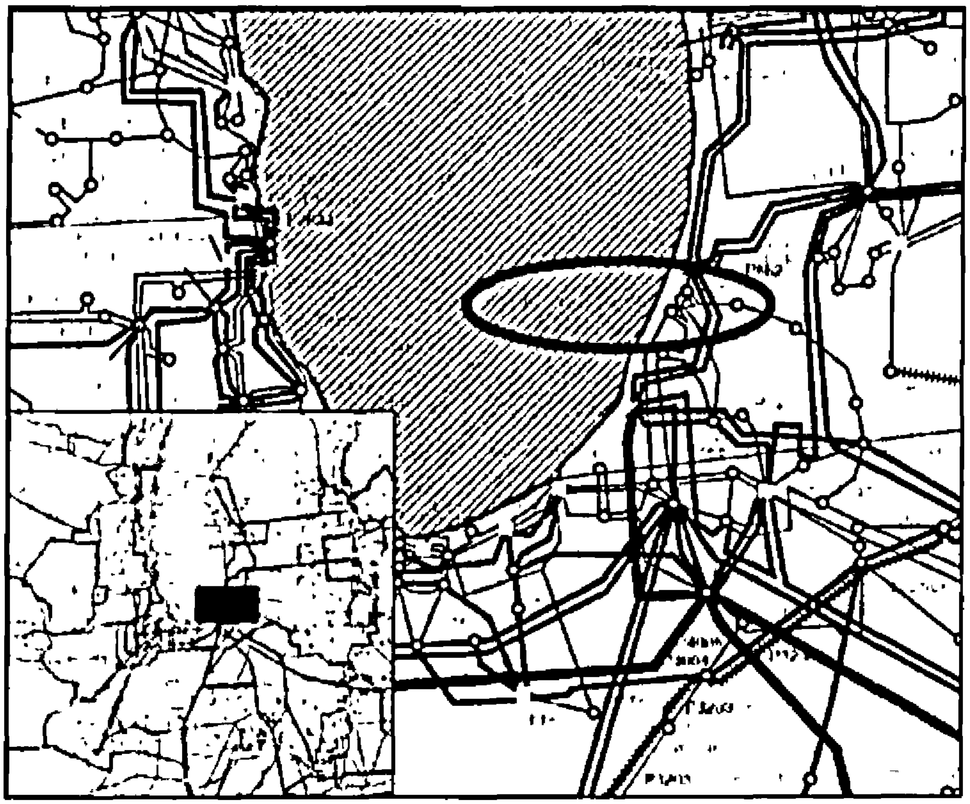


Figure C.2-15: Zone 7 Export Constraint

Zone 8 CIL

- Initial limit 578 MW
    - o Constraint: Vienna to Mt. Olive 115 kV line (Figure C.2-16)
        - ▪ Contingency: Mt. Olive to Eldorado 500 kV line
    - o Redispatch applied: 678 MW of generation, 10 generators in CLECO, AMMO, and EES
        - ▪ A CLECO generator outside zone was included in redispatch since the generator has a large impact on the constraint
- Next limit identified was 1,223 MW for the same constraint identified above.
    - o A rating upgrade was identified for the constrained facility
        - ▪ Applying the same redispatch scenario as noted above provided an updated limit of 1,602 MW.

- Current limit 1,602 MW

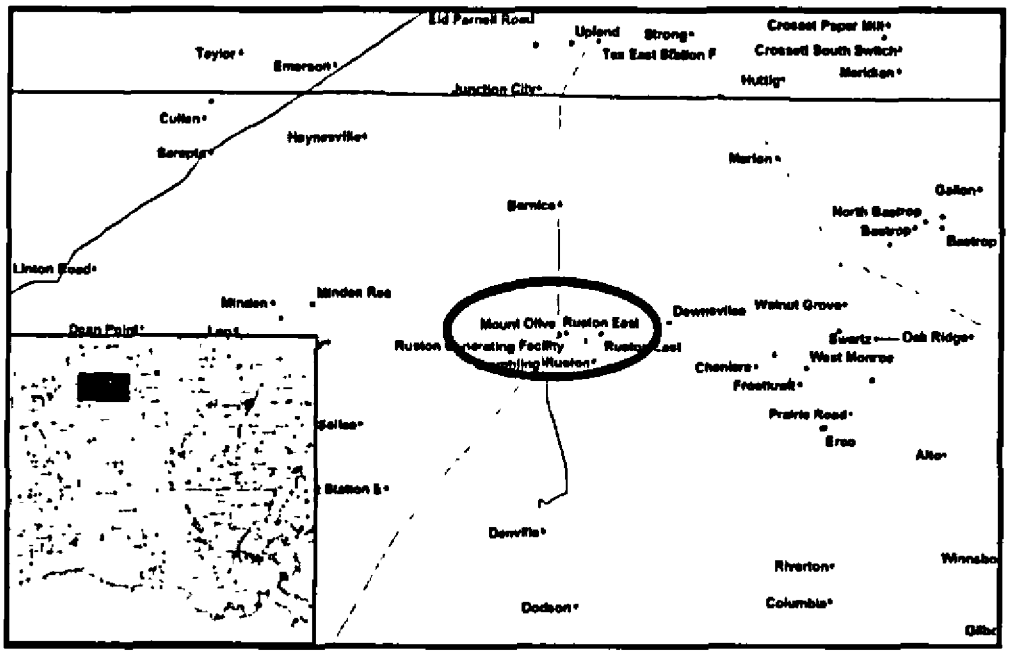


Figure C.2-16: Zone 8 Import Constraint

<u>Zone 8 CEL</u>

- Initial limit 3,018 MW
  - o Constraint: Butterfield (Woodlawn Rd) to Haskell 115 kV line (Figure C.2-17)
    - ▪ Contingency: Sheridan to Magnet Cove 500 kV line
  - o Redispatch applied: 674 MW of generation, 8 generators in EAI

- Current limit 3,080 MW
  - o Constraint: Russellville East to Russellville North 161 kV line (Figure C.2-18)
    - ▪ Contingency: Arkansas Nuclear One to Ft. Smith 500 kV line

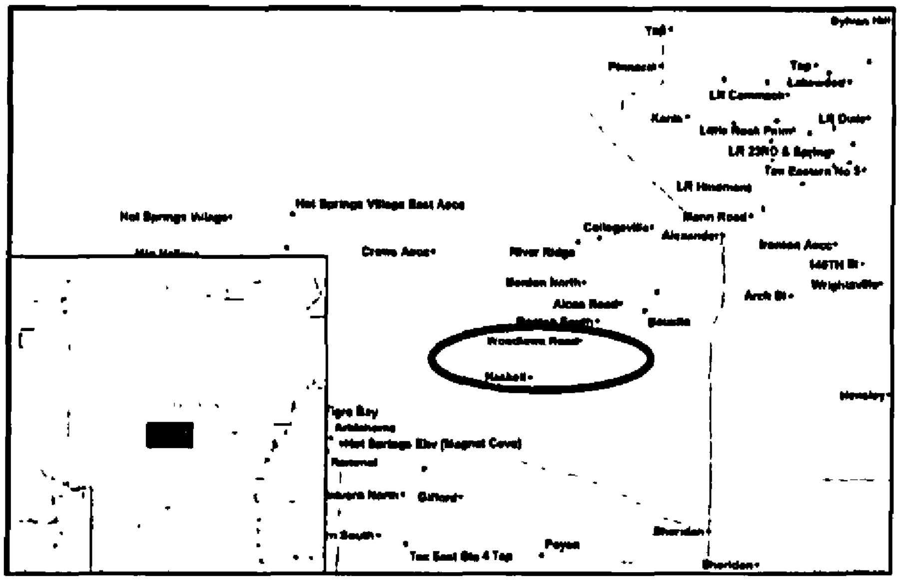


Figure C.2-17: Pre-redispatch Zone 8 Export Constraint

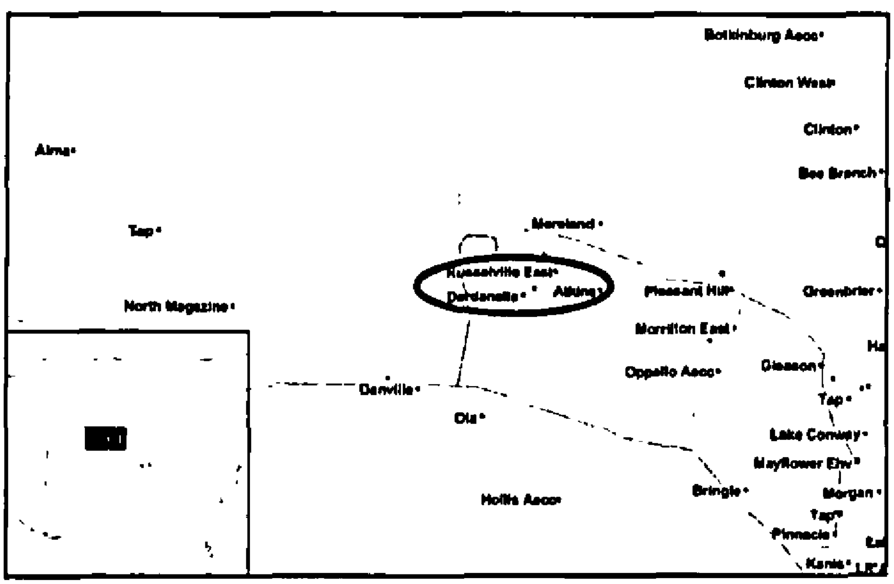


Figure C.2-18: Post-redispatch Zone 8 Export Constraint

<u>Zone 9 CIL</u>

- Initial limit 3,585 MW
  - o Constraint: Walnut Grove to Swartz 115 kV line (Figure C.2-19)
    - Contingency: Perryville to Baxter Wilson 500 kV line
  - o Multiple redispatch scenarios were tested and resulted in a more severe limiter
    - 720 MW, 10 generetors in EAI, PUPP, and AMMO.
    - 544 MW, 5 generators in EAI and PUPP

- Current limit 3,585 MW

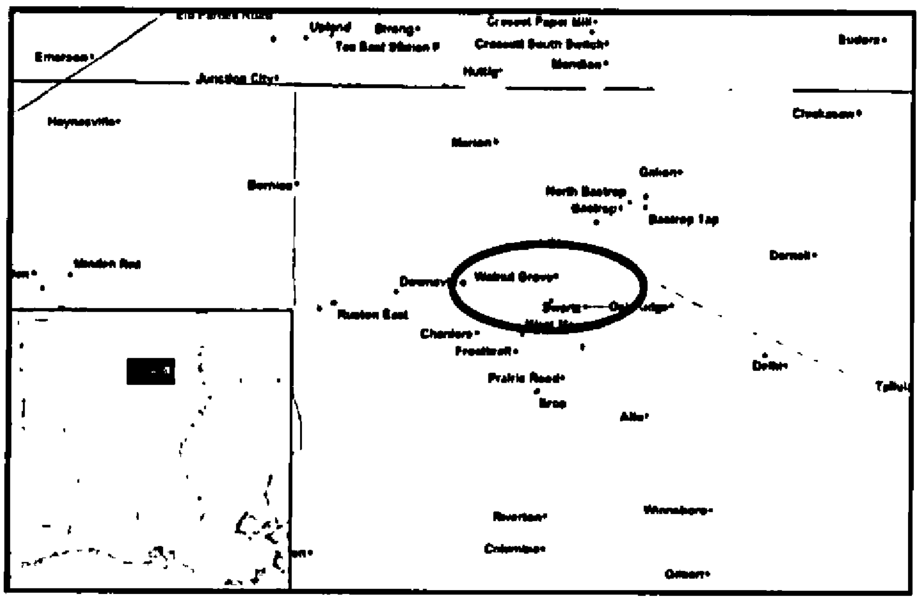


Figure C.2-19: Zone 9 Import Constraint

Zone 9 CEL

- Initial limit 2,051 MW
    - Constraint: Winnfield 230/115 kV transformer (Figure C.2-20)
        - Contingency: Montgomery to Clarence 230 kV line
    - Redispatch applied: 832 MW of generation, 10 generators in EES, SME, CLECO

- Current limit 3,616 MW for the same constraint identified above.

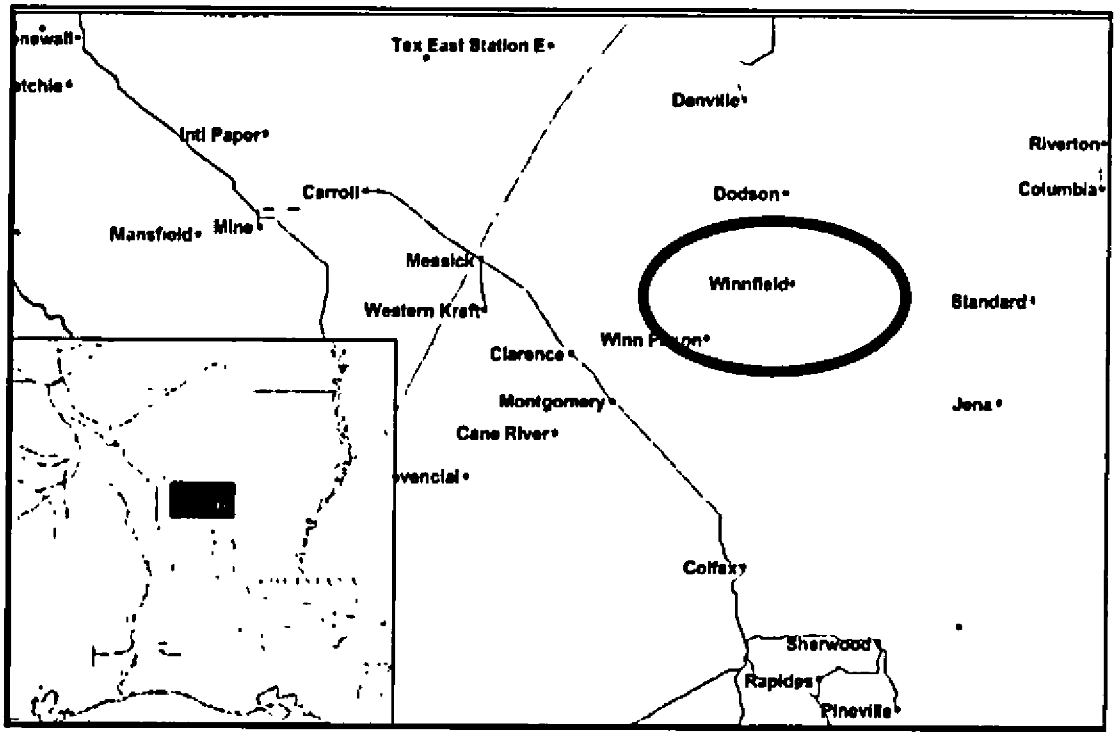


Figure C.2-20: Zone 9 Export Constraint

Appendix D Compliance Conformance Table

Requirements under: Standard BAL-502-RFC-02	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2014 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2014 through May 2015 and beyond. Analysis of Planning Year 2014 can be seen in Sections 5.1 and 6.1 Analysis of Future Years 2014-2022 can be seen in Sections 5.2 and 6.1
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion.)	Section 4.4.3 of this report outlines the utilization of LOLE in the reserve margin determination. "These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year."
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of load probability.	Section 4.2.1 of this report "Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 4.4.4 of this report "The minimum amount of capacity above the 50/50 net internal MISO Coincident Peak Demand required to meet the reliability criteria was used to establish the PRM values."
R1.2 Be performed or verified separately for each of the following planning years	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In sections 5.1 and 6.1, a full analysis was performed for planning year 2014.
R1.2.2 Perform an analysis or verification at a minimum for one year in the two-through five-year period and at a minimum one year in the six- though 10-year period.	Sections 5.2 and 6.1 show a full analysis was performed for future planning years 2018 and 2023.

Requirements under: Standard BAL-502-RFC-02	Response
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year	Analysis was performed
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.
R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts) • Load diversity • Seasonal load variations • Daily demand modeling assumptions (firm, interruptible) • Contractual arrangements concerning curtailable/interruptible Demand	Median forecasted load – In section 4.3 of this report: "For the 2014-2015 LOLE analysis, the hourly LRZ load shape was a product of the historical load shape used as well as the 50/50 demand forecasts submitted by Load Serving Entities (LSE) through the MECT tool." Load Forecast Uncertainty – A detailed explanation of the LFU calculations is given in section 4.3.1 as well as appendix A. Load Diversity/Seasonal Load Variations - Section 4.3 of this report details the historic hourly load profiles used with their inherent diversity and seasonal variations. "Local Resource Zones 1 through 7 used the 2005 historical load shape while zones 8 and 9 used the 2006 historical load shape. For MISO Midwest, the 2005 load shape provides a typical load shape for the Midwest region as well as inherent conservative external support due to external load shapes. With the integration of MISO South, MISO chose to use the 2006 historical shape as the 2005 shape represented an extreme weather year for the South region during Hurricane Katrina." Demand Modeling Assumptions/Curtailable and Interruptible Demand – All Load Modifying Resources must first meet registration requirements through Module E. As stated in section 4.2.1: "Each demand response program was modeled individually with a monthly capacity and energy, which is limited to the number of times each program can be called upon as well as limited by duration."

Requirements under: Standard BAL-502-RFC-02	Response
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area • Resource planned outage schedules, deratings and retirements • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration • Criteria for including planned resource additions in the analysis	Section 4.2. details how historic performance data and seasonal ratings are gathered, and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is shown in section 4.4.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves	Section 3 of this report details the transfer analysis to capture transmission limitations that prevent the delivery of generation reserves. The results from this analysis are shown in section 3.3.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Inclusion of planned transmission addition assumptions is detailed in section 3.3.1.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering transmission limitations into the study area.	Section 4.4 provides the analysis on the treatment of external support assistance and limitations.

Requirements under: Standard BAL-502-RFC-02	Response
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel • Common mode outages that affect resource availability • Environmental or regulatory restrictions of resource availability • Any other demand (load) response programs not included in R1.3.1 • Sensitivity to resource outage rates •Impacts of extreme weather/drought conditions that affect unit availability • Modeling assumptions for emergency operation procedures used to make reserves available • Market resources not committed to serving load (uncommitted resources) within the Planning Coordinator area	Fuel availability, environmental restrictions, common mode outage and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 4.2. The use of demand response programs are mentioned in section 4.2. The effects of resource outage characteristics on the reserve margin are outlined in section 4.4.4 by examining the difference between PRM_{ICAP} and PRM_{UCAP} values.
R1.5 Consider transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 3 treats worst-case theoretical outages by Perform First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category A (system intact) and Category B (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	MISO internal resources are among the quantities documented in the tables provided in sections 5 and 6.
R1.7 Document that all load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	MISO load is among the quantities documented in the tables provided in sections 5 and 6; the balance of MISO Reliability Coordination loads are included among the loads in the external Zone 1 "Ex 1 WAUE" of Figure 4.4-3.

Requirements under: Standard BAL-502-RFC-02	Response
R2 The Planning Coordinator shall annually document the projected load and resource capability, for each area or transmission constrained sub-area identified in the Resource Adequacy analysis.	In Section 5 and 6, the peak load and estimated amount of resources for planning years 2014, 2018 and 2023 are shown. This includes the detail for each transmission constrained sub-area.
R2.1 This documentation shall cover each of the years in Year One through 10.	Section 5.2 and Table 5-3 shows the three calculated years, and estimated in-between years, by interpolation.
R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	Section 5.2 and Table 5-3 shows the three calculated years in red-font text.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One	The 2014 LOLE Study Report documentation is posted on November 1 prior to the planning year.

Appendix E Acronyms List Table

BA	Balancing Authority
BPM	Business Practice Manual
BTMG	Behind-the-Meter Generation
CBMEP	Cross Border Market Efficiency Project
CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
CSA	Coordinated Seasonal Assessment
DF	Distribution Factor
DSM	Demand-Side Management
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
EV	Energy Velocity
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
GVTC	Generator Verification Test Capacity
ICAP	Installed Capacity
IEEE	Institute of Electrical and Electronics Engineers
IMM	Independent Market Monitor
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFU	Load Forecast Uncertainty
LOL	Loss of load
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand

MRO	Midwest Reliability Organization
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corp.
NDC	Net Dependable Capacities
NSI	Net Scheduled Interchange
OMC	Outside Management Control
PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM_{ICAP}	PRM Installed Capacity
PRM_{UCAP}	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
PSS MUST	Power System Simulator for Managing & Utilizing System Transmission
RECB	Regional Expansion Criteria and Benefits
RFC	Reliability First Corp.
RPM	Reliability Pricing Model
RTO	Regional Transmission Operator
SERC	SERC Reliability Corporation
TPL	Transmission Planning
TSR	Transmission Service Request
TTC	Total Transfer Capability
TVA	Tennessee Valley Authority
UCAP	Unforced Capacity
XEFORd	Equivalent Forced Outage Rate demand excluding events Outside Management Control